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PUBLIC SERVICE
COMMISSION

a PPL company

Jeff DeRouen, Executive Director
Public Service Commission of Kentucky
211 Sower Boulevard
P. O. Box 615
Frankfort, Kentucky 40602

**Louisville Gas and Electric Company**
State Regulation and Rates
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September 23, 2011

**RE:** ***In the Matter of: The Application of Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Approval of Its 2011 Compliance Plan for Recovery by Environmental Surcharge*** **- Case No. 2011-00162**

Dear Mr. DeRouen:

Pursuant to the Commission's Order dated September 16, 2011 in the above-referenced matter, with this letter Louisville Gas and Electric Company (LG&E) is filing one (1) original in paper format of the attachments to LG&E's response to the Metro Housing Coalition's (MHC) First Set of Requests, Question No. 6 dated July 12, 2011, previously provided in electronic format on July 25, 2011.

Should you have any questions regarding the enclosed, please contact me at your convenience.

Sincerely,

Robert M. Conroy

cc: Parties of Record (w/o attachments)

In the Matter of:

| | |
|---|---|
| THE APPLICATION OF LOUISVILLE GAS AND | ) |
| ELECTRIC COMPANY FOR CERTIFICATES | ) |
| OF PUBLIC CONVENIENCE AND NECESSITY | ) CASE NO. |
| AND APPROVAL OF ITS 2011 COMPLIANCE | ) 2011-00162 |
| PLAN FOR RECOVERY BY ENVIRONMENTAL | ) |
| SURCHARGE | ) |

**Response to MHC First Set of Requests**
**dated July 12, 2011**
**One Paper Copy for Question No. 6**

**Filed – September 23, 2011**

**LOUISVILLE GAS AND ELECTRIC COMPANY**

**Response to MHC First Set of Requests Dated July 12, 2011**

**Case No. 2011-00162**

**Question No. 6**

**Witness: Lonnie E. Bellar / John N. Voyles, Jr. / Charles R. Schram**

Q-6. In the Staff Report on the 2008 Integrated Resource Plan for LG&E and KU, Commission Case No. 2008-00148, Staff noted on p. 14 that: "LG&E and KU demonstrated that they are actively considering the potential effects of pending climate change legislation even though there is a lot of uncertainty regarding exact legislative requirements. They should continue to actively model and incorporate the potential effects of climate change legislation into future IRP filings." That same Report noted on p. 12 that "[t]he eventual realization of some form of [stricter limits on the emission of C02 and other greenhouse gasses (sic)] could have major impacts on LG&E and KU and their customers."

(a) Please provide any assessment or analysis conducted or contracted by LG&E that discusses or quantifies the range of costs, and range of options to respond to additional controls that would be required by various climate change bills that have been proposed in Congress during the last two legislative sessions, including the House-passed bill from last Congressional Session.

(b) Please provide the results of any modeling or projection conducted by or for LG&E with respect to the potential costs of compliance with climate change legislation or EPA regulation.

(c) Please provide any comparative assessment undertaken of the costs of various demand-side, energy efficiency, or renewable energy sources relative to installation of controls on the LG&E units, with the cost of controls on emissions of CO2 incorporated into the controls.

(d) Please explain, to the extent that such an assessment has not been undertaken, how the costs proposed to be incurred for compliance with current and proposed rulemakings are prudent, in light of the acknowledgment by PSC Staff of the major effect that stricter limits could have on the existing generation capacity.

A-6. a. Please see the response to KPSC Question No. 2. Over the past several years, the Companies have been monitoring the various climate change bills proposed in legislation and evaluating the potential impact of such climate change legislation and

EPA regulations. Please see the various reports and communication material provided on the CD in the folder labeled Question 6.

b. Please see the response to part a.

c. No additional demand side management or energy efficiency analyses are available. In the 2011 IRP filing, the Companies evaluated various renewable energy options as part of the supply side screening process.

d. Potential $CO_2$ regulations could take many forms, but the EPA has indicated by the "Tailoring Rule" that it will impose a BACT approach. It is unclear if, or when, commercially viable and scalable technologies will become available which could impose additional costs on fossil fueled generation fleets.

The Companies agree with the KPSC 2008 IRP report that stricter limits on the emission of $CO_2$ could have major impacts on LG&E/KU and our customers; however, currently it is unclear as to what the impact would be on individual generating units on our system. The regulations that are the subject of this filing are known and provide very little flexibility, generally requiring retrofits for continued operation of individual units. Thus, the Companies must comply with the regulations discussed in the Application for the 2011 Environmental Compliance Plan. These regulations take effect as early as 2012 and the Company is obligated to comply while providing reliable electricity in a least-cost manner.

# New/proposed EPA regulations will increase cost of coal-fired electricity

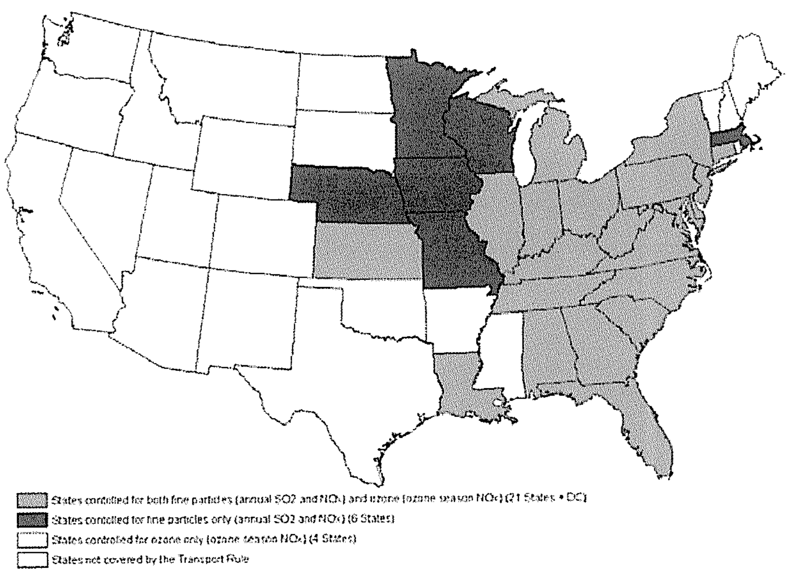
*2011 KAM Energy Summit*
*April 20, 2011*

# Unprecedented number of proposed regulations

- EPA proposals will have a major impact on coal-fired utilities and their customers.
- New Air Regulations
- New Coal Combustion Residual and Water Regulations

# New air regulations

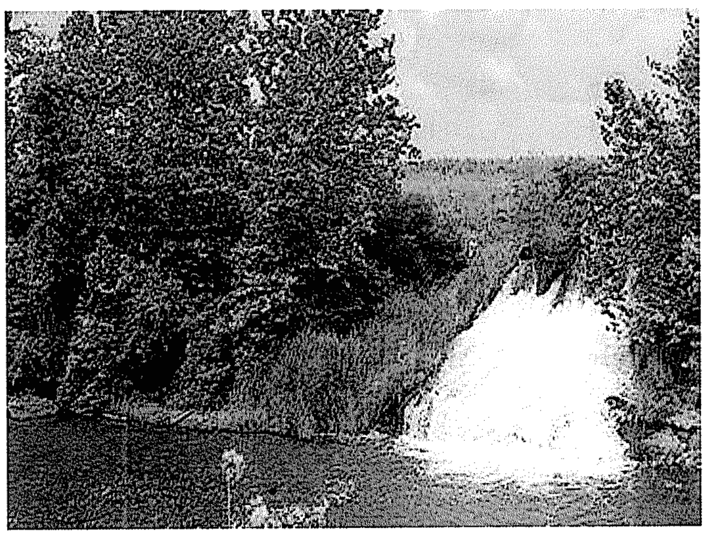
- National Ambient Air Quality Standards (NAAQS)
  - Ground level air monitors across the state
  - Compliance by 2016 or 2017
- Clean Air Transport Rule (CATR)
  - Regional air pollution effects
  - Possible compliance dates of 2012 and 2014.

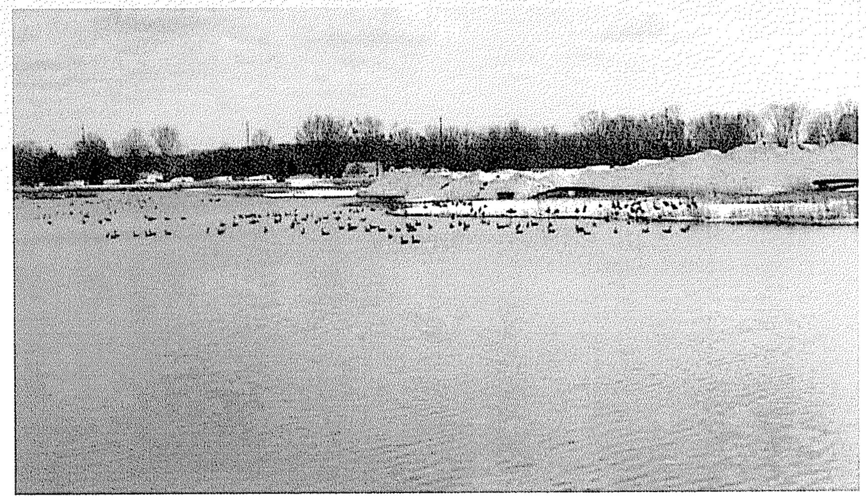



- Maximum Achievable Control Technology (MACT) for Hazardous Air Pollutants (HAPs)
  - Mercury, Arsenic, Selenium
  - Acid aerosols
  - Plant-by-plant controls
  - Compliance by 2015 or 2016
- $CO_2$ Best Available Control Technology (BACT)
  - Permits for new or modified sources beginning Jan. 2011 required BACT analysis
  - Greenhouse gas new source standards; proposal by July 2011

# New coal combustion residuals and water regulations

- Coal Combustion Residuals (CCR)
  - Hazardous or Non-hazardous
  - Wet ponds must have liners or convert to dry storage
  - Draft rule expected in 2012
  - Compliance within 5 years of final rule





- Water quality (1974 Clean Water Act)
  - Water Withdrawal proposed rule released March 28; expect final rule July 2012
  - Water Discharges draft rule expected mid 2012 with final rules by 2013, then compliance

# Alternative supply choice — retire coal and switch to gas


*Source: Effingham County Power, LLC*
*a Progress Energy Company*

- Natural Gas Combined Cycle units
  - Zero $SO_2$ and 50% less NOx emissions
  - Capital costs of \$600M to \$800M each

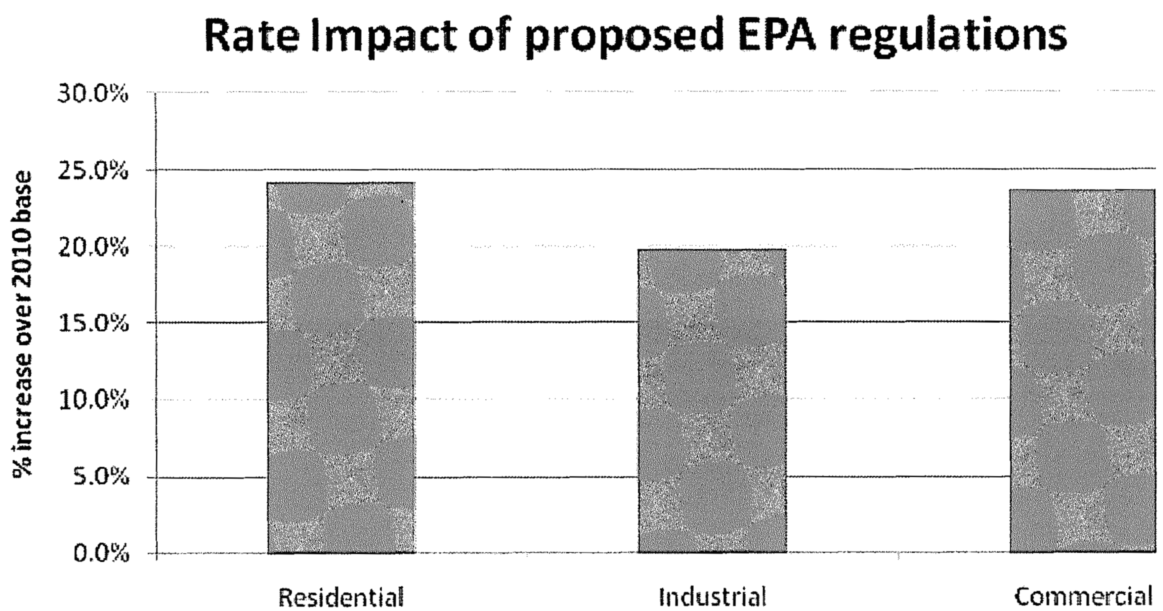
# LG&E and KU estimate approximately $4 billion in capital costs needed over next ten years

| Regulation | Capital ($M) | Annual Operating Expense ($M) |
|---|---|---|
| Air | $3,000 | $150 – 300 |
| CCR | $700 | *To be determined* |
| Water | *To be determined* | |

LG&E KU
PPL companies

# Potential rate impact to LG&E and KU customers of proposed EPA regulations

- Due to these regulations, by 2019, rates could increase by more than 20% and almost $550 million annually




*Note: This calculation does not include potential compliance costs for water regulations, Renewal Portfolio Standards (RPS) or carbon dioxide ($CO_2$) reductions*

LG&E KU PPL companies

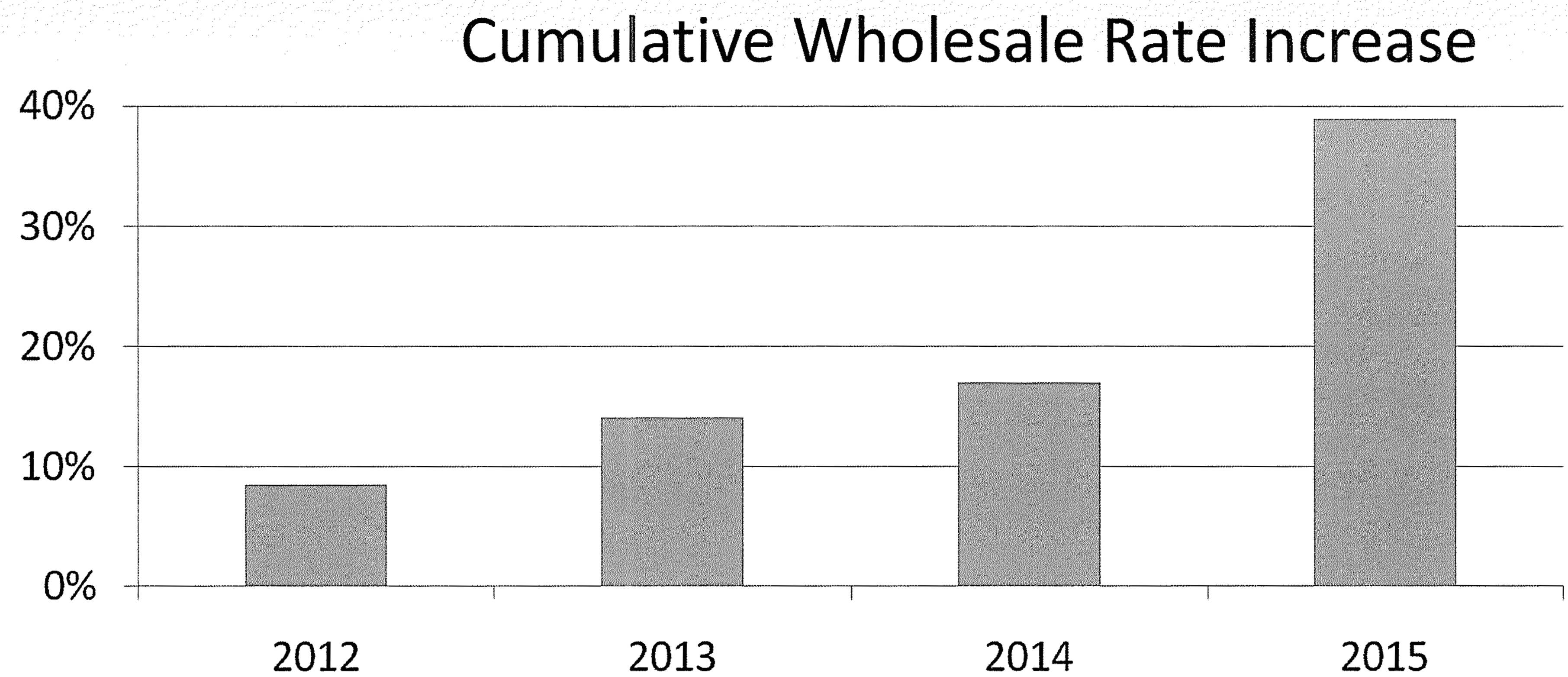
# Big Rivers estimates the following capital investments through 2015 to comply with pending EPA regulations

| Regulation | Capital ($M) |
|---|---|
| CATR | $138M |
| HAPs-MACT | $338M-$846M |
| CCR | $237M |
| Water | To be determined |

Incremental Operating Expenses are yet to be determined

Big Rivers
ELECTRIC CORPORATION

# By 2015, wholesale rates could increase by nearly 40% to comply with pending EPA regulations




Note: This calculation includes capital costs but does not include incremental operating expenses, potential compliance costs for water regulations or carbon dioxide ($CO_2$) reductions.

Big Rivers
ELECTRIC CORPORATION

# EKPC estimates compliance with pending EPA regs will mean additional costs in coming years:

| Regulation | Capital ($M) |
|---|---|
| CATR | $40M annually |
| HAPS | $20-30M |
| CCR | $644M |
| Water | $40-70M |

EAST KENTUCKY POWER COOPERATIVE

A Touchstone Energy Cooperative

# These costs come in addition to hundreds of millions already spent on compliance in recent years:

- In recent years, EKPC already has spent more than $1.8 billion on new plants featuring clean-coal technology and to retrofit existing plants to meet more-stringent standards.
- The EPA regs currently pending could cost an additional $700 million and cause rates to rise by more than 20 percent.

EAST KENTUCKY POWER COOPERATIVE

A Touchstone Energy Cooperative

# Estimate at least $1 billion in capital costs needed over next ten years

| Regulation | Capital ($M) | Annual Operating Expense ($M) |
|---|---|---|
| *Air* | *$800 – 1,200* | *$40 – 60* |
| *CCR* | *$300 - 400* | *$.4 - .5* |
| *Water* | *Not applicable* | |

*The cost to comply with CCR and Transport will be a 30 - 40% rate increase.*

AEP KENTUCKY POWER®
A unit of American Electric Power

# What are Kentucky's electric utilities doing?

- Evaluating multiple compliance alternatives.
- Participating in industry efforts to advocate more reasonable regulations and timelines.
- Communicating our concerns directly with EPA on proposed regulations.
- Educating elected officials, regulators and customers on the effect of the federal regulations will have on their electric bill.

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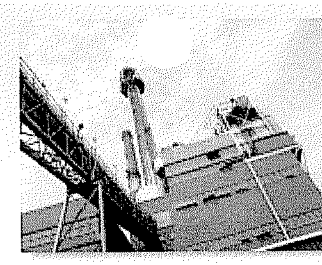
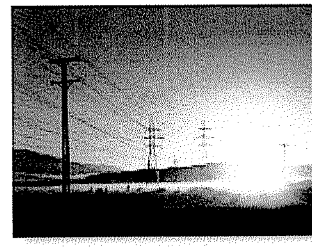
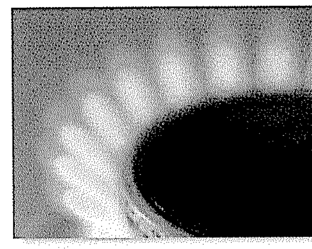
# New/proposed EPA regulations will increase cost of coal-fired electricity

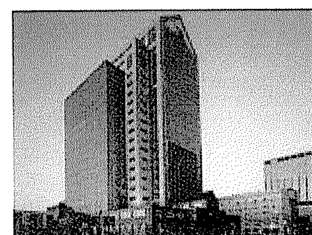
# LG&E And KU Future Plans

## Consumer Advisory Panel – June 2, 2011



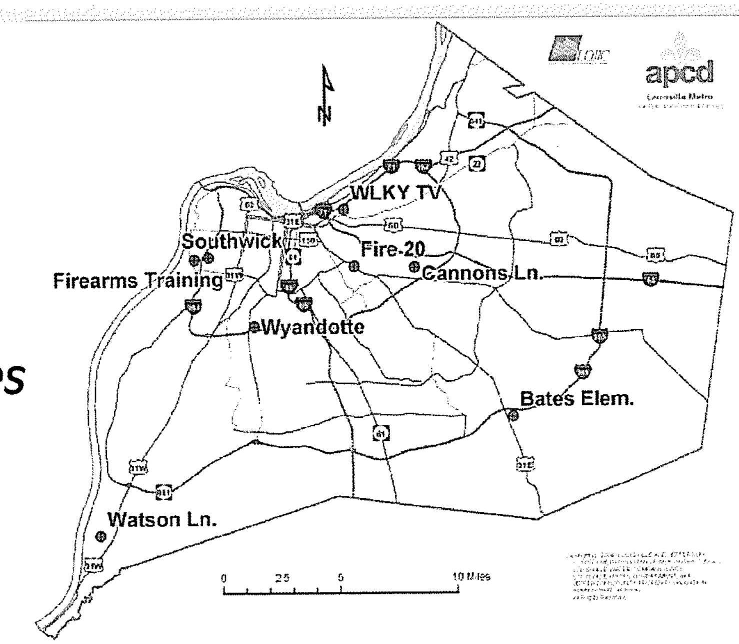


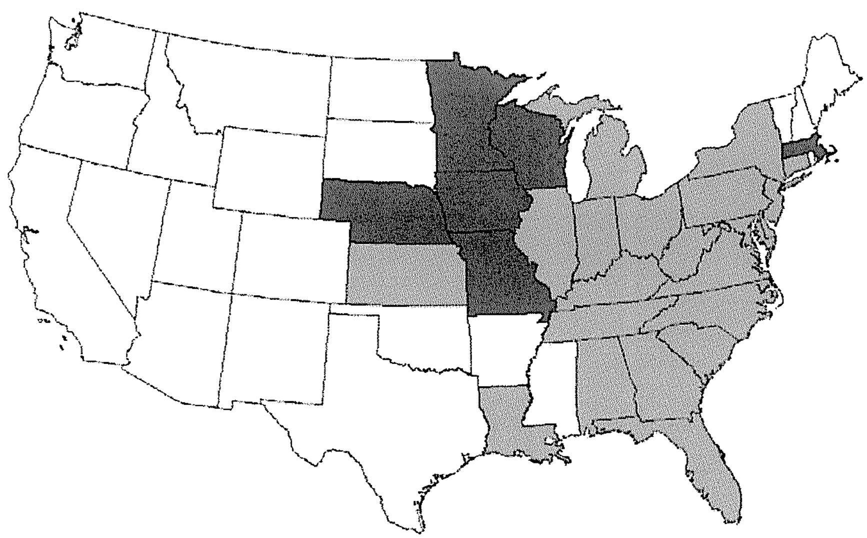




# New air regulations

- *National Ambient Air Quality Standards (NAAQS)*
  - — *Ground level air monitors across the state*
  - — *Jefferson Co. has detected exceedances*
  - — *Compliance by 2016 or 2017*



States controlled for both fine particles (annual $SO_2$ and $NO_x$) and ozone (ozone season $NO_x$) (21 States + DC)
States controlled for fine particles only (annual $SO_2$ and $NO_x$) (6 States)
States controlled for ozone only (ozone season $NO_x$) (4 States)
States not covered by the Transport Rule

- *Clean Air Transport Rule (CATR)*
  - — *Regional air pollution effects*
  - — *Possible compliance dates of 2012 and 2014.*



LG&E KU
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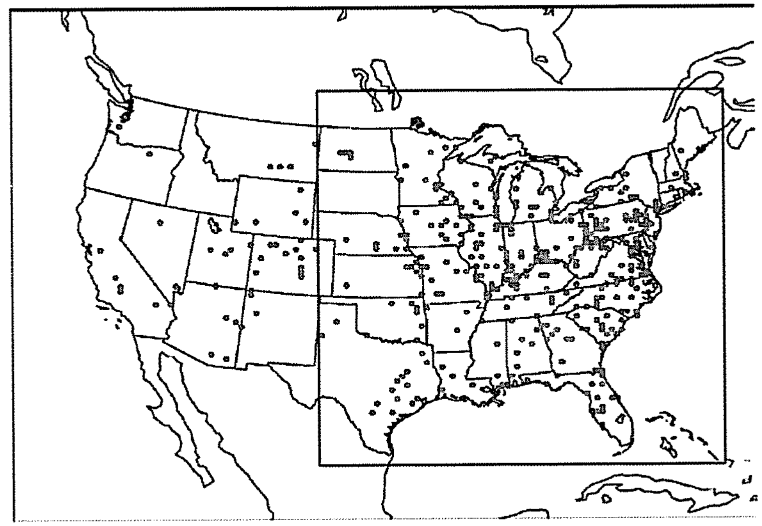
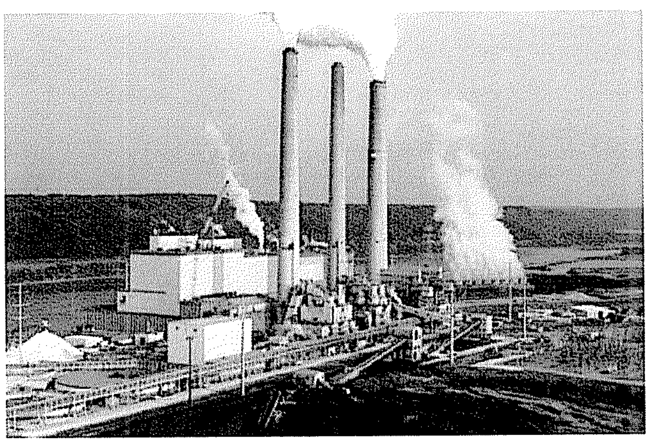
# New air regulations

- *Maximum Achievable Control Technology (MACT) for Hazardous Air Pollutants (HAPs)*
  - *Mercury, Arsenic, Selenium*
  - *Acid aerosols*
  - *Final rule expected Nov. 2011*
  - *Compliance by 2015 or 2016*





- *$CO_2$ Best Available Control Technology (BACT)*
  - *Permits for new or modified sources beginning Jan. 2011 required BACT analysis*
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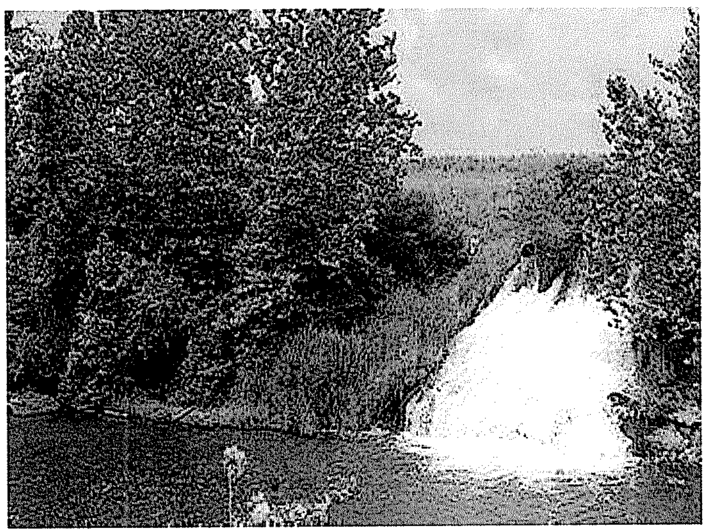

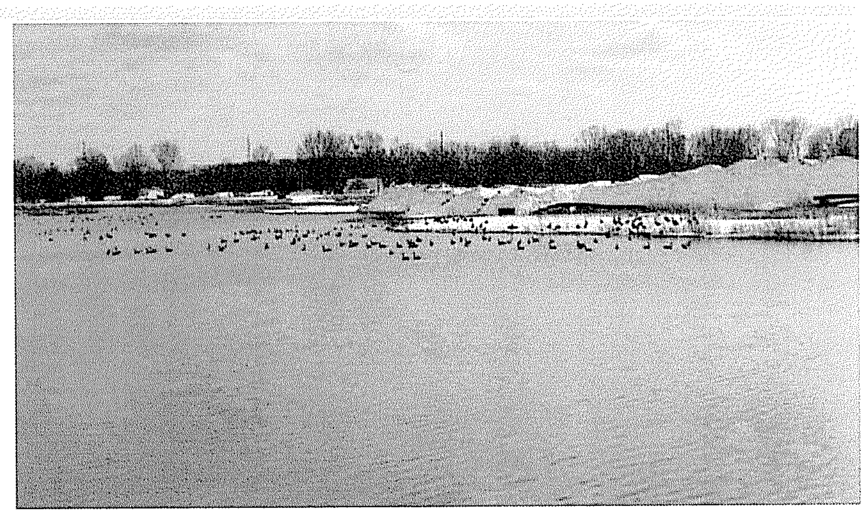

- *Water quality (1972 Clean Water Act)*
  - *Water Withdrawal proposed rule released March 28; expect final rule July 2012*
  - *Water Discharges draft rule expected mid 2012 with final rules by 2013, then compliance*



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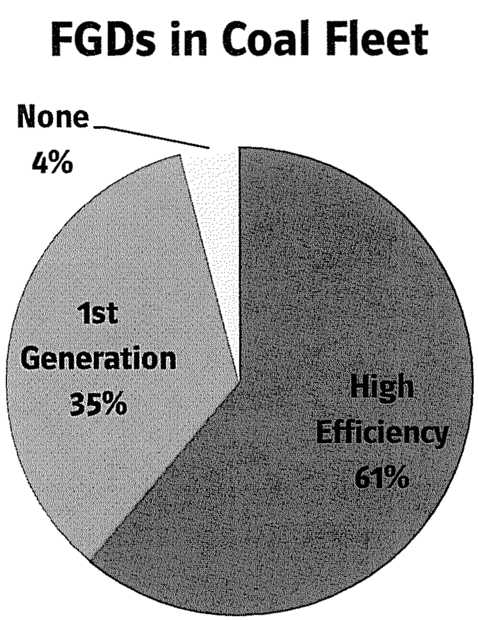
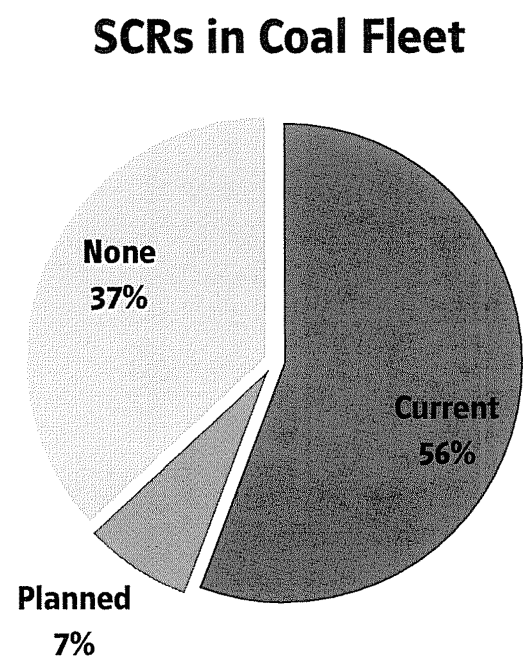
# LG&E/KU's coal fleet already has high level of $SO_2$ and $NO_X$ control technologies...

*...but some additions or enhancements will be required.*



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# $SO_2$ technology options for NAAQS & CATR

- *FGDs with high removal efficiency*
  - *$5,000 to $11,000 per ton removed*
  - *Capital Costs of $300M to $700M each*



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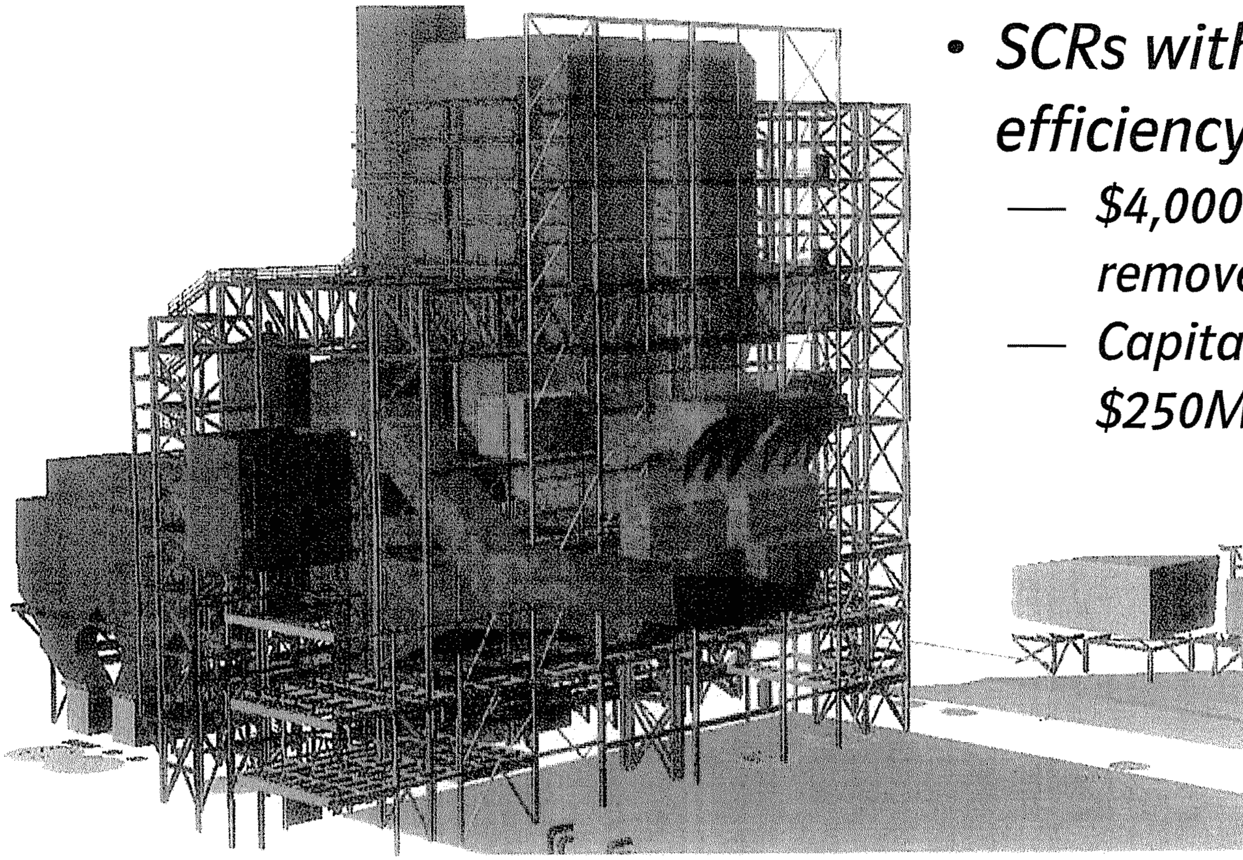
# $NO_X$ technology options for NAAQS & CATR



- *SCRs with high removal efficiency*
  - *$4,000 to $8,000 per ton removed*
  - *Capital costs of $100M to $250M each*



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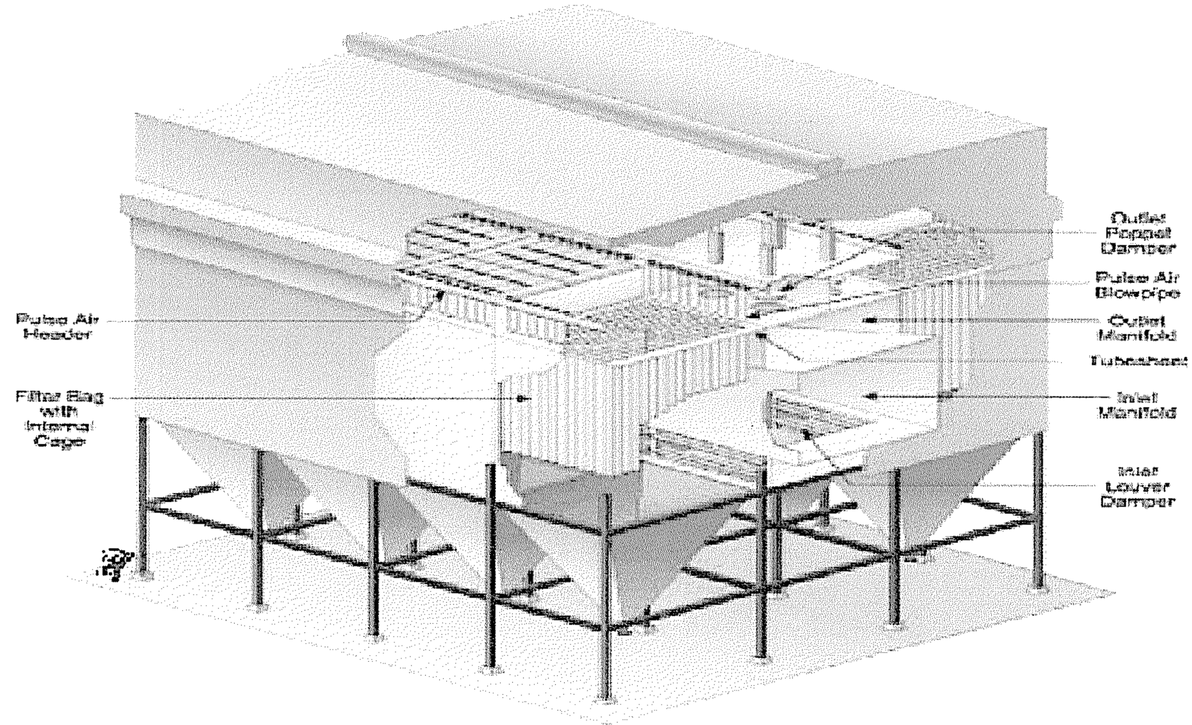
# HAP technology options for MACT rules

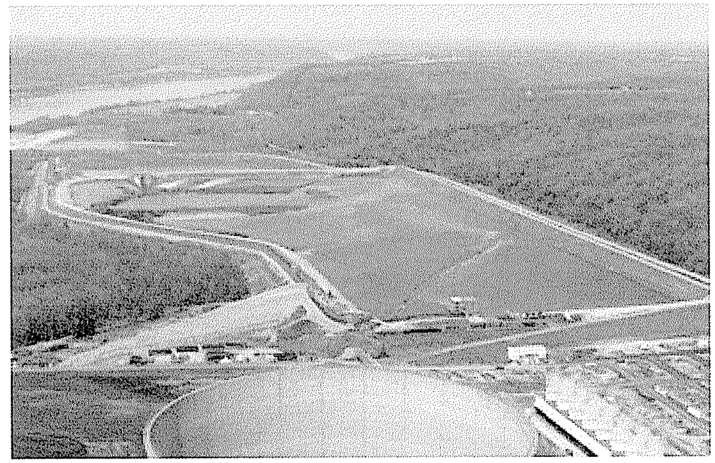
*Fabric Filter particulate controls with carbon injection for high mercury and particulate removal efficiencies*

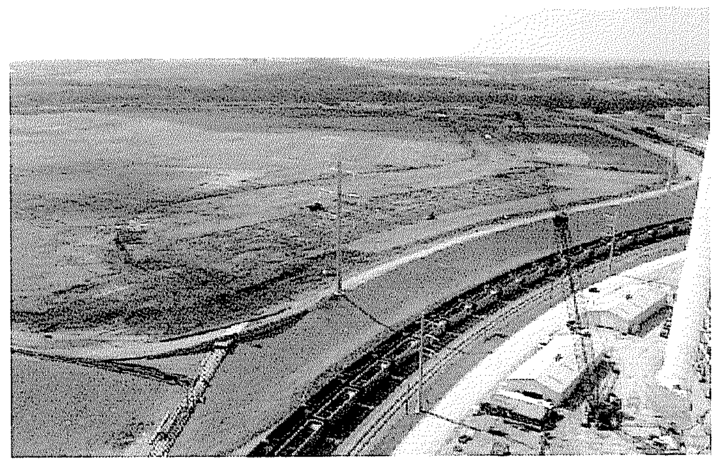
- *Capital Costs of $50M to $175M each*
- *$150,000 to $450,000 per pound of mercury removed*



# Proposed EPA CCR regs would require dry storage & closing existing ash ponds

- *Retrofit or close 21 ponds*
  - *10 ash ponds*
  - *11 process/runoff ponds*
- *Build landfills for future storage*
- *Construct new process water ponds for each operating site*
- *Decommissioning ponds will cost an estimated $700 million*







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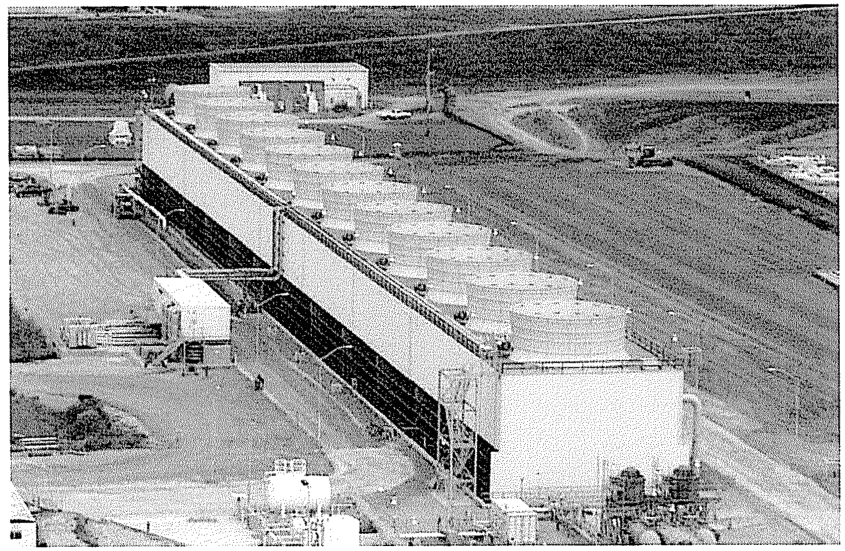
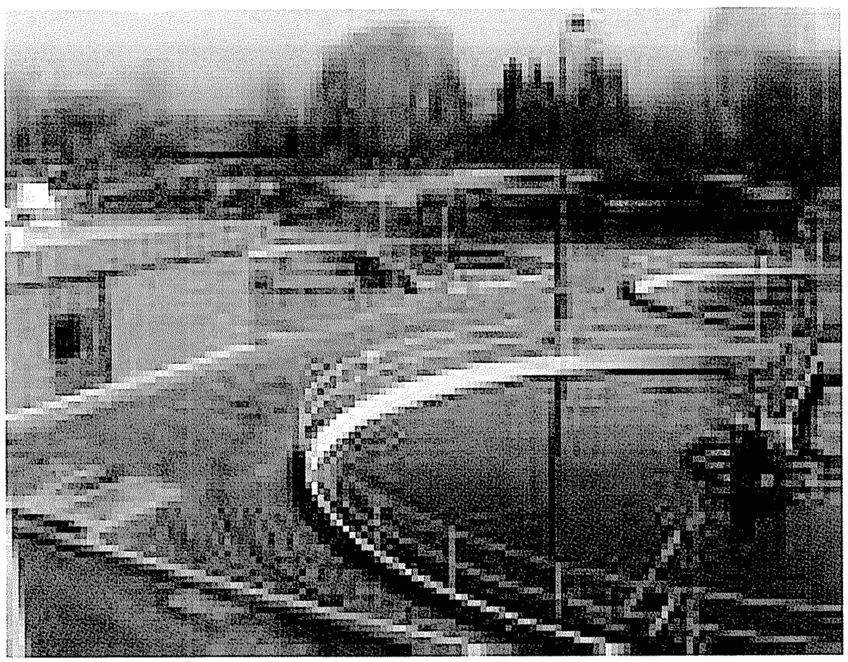
# Increased water withdrawal and discharge requirements

- *Cooling Water Withdrawal*
  - *Units without cooling towers*
    - *Cane Run*
    - *Green River*
    - *Mill Creek 1*
    - *Tyrone*
  - *All stations have intake structures*





- *New water discharges standards (effluent guidelines)*
  - *Physical-chemical treatment*
  - *Biological treatment systems*
  - *Cost of $40 - $300 million for each site*



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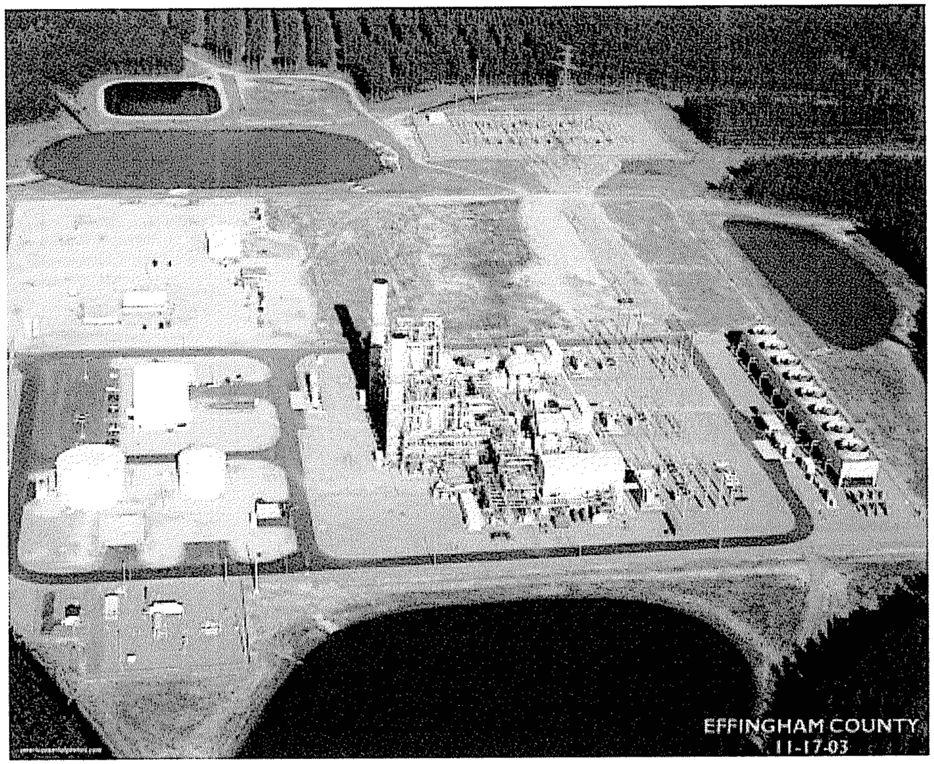
# Alternative supply choice — retire coal and switch to gas




*Source: Effingham County Power, LLC*
*a Progress Energy Company*

- *Natural Gas Combined Cycle units*
  - *Zero $SO_2$ and 50% less $NO_x$ emissions*
  - *Capital costs of $600M to $800M each*



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# LG&E and KU estimate approximately $4 billion in capital costs needed over next ten years

| Regulation | Capital ($M) | Annual Operating Expense ($M) |
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| *Air* | *$3,300* | *$150 - 300* |
| *CCR* | *$700* | *To be determined* |
| *Water* | *To be determined* | *To be determined* |

*Note: This calculation does not include potential compliance costs for water regulations, Renewal Portfolio Standards (RPS) or carbon dioxide ($CO_2$) reductions*



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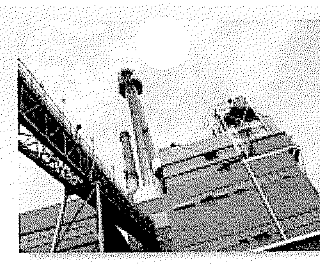
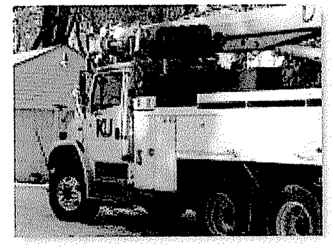
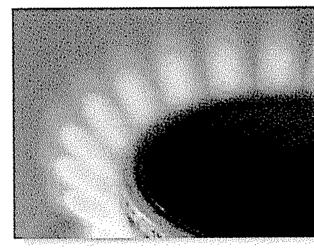
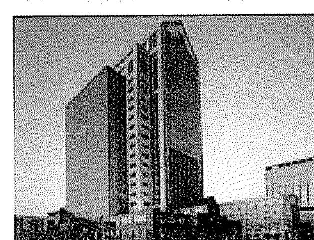
# Environmental Regulations and the Environmental Cost Recovery (ECR) Filing





# 2010-11 Engineering Activities & Studies

- *Control equipment studies for all stations*
- *Mill Creek scrubber (FGD) Performance Improvement study & structural review*
- *Precipitator (ESP) upgrade study*
- *Flow modeling studies for widening the operating range for unit equipped with selective catalytic reduction (SCR) controls*
- *E.W. Brown study of a smaller ash pond, with delayed conversion to a landfill*

# Engineering & Analytical Findings/Results

- *Demonstrate prudency of installing emission controls (versus retiring units)*
  - *Installing controls at Cane Run, Green River and Tyrone not cost effective*
- *HAPs (MACT)*
  - *Fabric Filter Baghouses needed for mercury control*
- *NAAQS & CATR*
  - *Construct new FGD/chimney for Mill Creek Units 1 & 2*
  - *Construct new FGD/chimney on Mill Creek Unit 4*
  - *Upgrade existing operations for units with SCR to improve utilization*
- *CCR*
  - *Convert ash pond project at Brown to a landfill*



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# Air Compliance Costs

## ECR Filing

- *Total company capital costs estimated at $2.5 billion*
  - *KU approximately $1.1 billion*
  - *LG&E approximately $1.4 billion*

- *Projected rate impacts*
  - *KU estimated at 12.2% by 2016*
  - *LG&E estimated at 19.2% by 2016*

## Replacement Energy*

- *Actions on Cane Run, Green River and Tyrone forthcoming*
  - *Estimated cost of up to $800 million*
  - *KU estimated additional 2%*
  - *LG&E estimated additional 5%*

** The Replacement Energy and the $700 million associated with CCR regulations are not included in this ECR filing*



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# Coal still Dominant Energy Source despite Retirements and New Gas Generation

- *Environmental regulations result in 800 MW of retirements at Cane Run, Green River and Tyrone in 2016*
  - *Represents 13% of today's LG&E/KU coal fleet*
  - *Reduces coal burn by 2.0 million tons annually*
- *Expect replacement energy to come from natural gas sources by 2016 to meet 875 MW reserve margin deficit*
  - *Coal will still provide ~90% of energy in 2016 (compared to 97% currently)*



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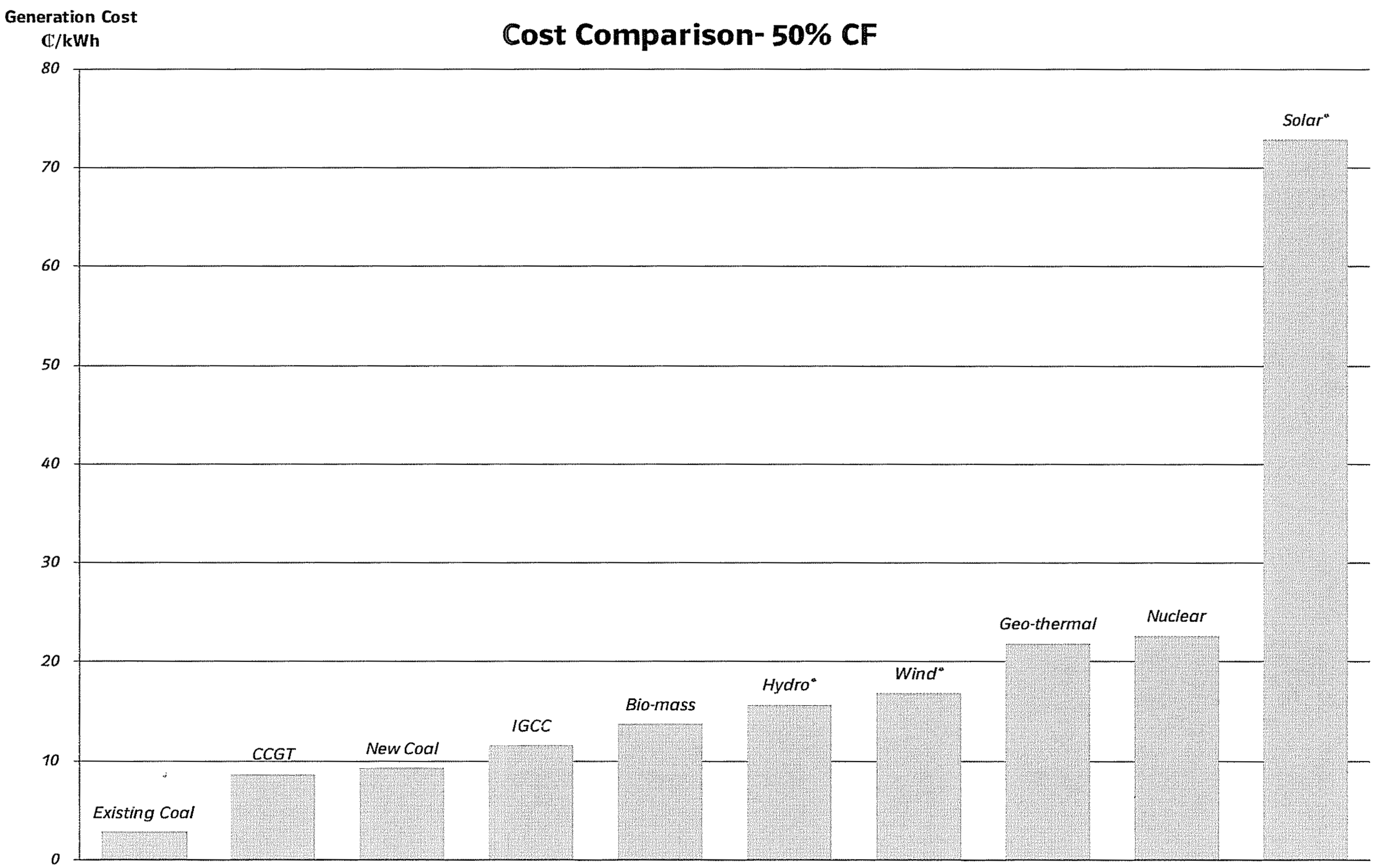
# Technologies Cost Comparison – 50% Capacity Factor (Intermediate Load)




*Reflects cost of additional capacity required to meet a 50% capacity factor



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# Replacement Energy Decision Process

- *New generation decisions subject to market alternatives compared to self-build options (Request For Proposal (RFP) was issued late last year)*
- *Final decisions require further study and regulatory approvals*
- *Expect to make a decision in July, including a CPCN filing with the KPSC later in the 3rd quarter*

# Risks for Delivering the Plans

- *Schedule — completion by 2016*
- *Major equipment lead times*
- *Equipment availability for fans and electrical motors*
- *Shop fabrication space*
- *Engineering and construction labor availability*
- *Cost escalations*

*Questions ?*

PPL companies

# Appendix

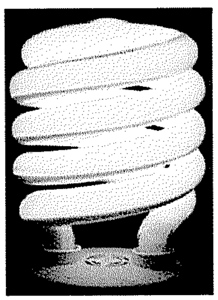
## *Acronyms*

- *BACT (Best Available Control Technology)*
- *CATR (Clean Air Transport Rule)*
- *CCGT (Combined Cycle Combustion Turbine)*
- *CCR (Coal Combustion Residuals)*
- *CPCN (Certificate of Public Convenience and Necessity)*
- *ECR (Environmental Cost Recovery)*
- *EPA (Environmental Protection Agency)*
- *ESP (Electrostatic Precipitator)*
- *FGD (Flue Gas Desulfurization)*
- *HAPs (Hazardous Air Pollutants)*
- *IGCC (Integrated Gasification Combined Cycle)*
- *KPSC (Kentucky Public Service Commission)*
- *MACT (Maximum Available Control Technology)*
- *NAAQS (National Ambient Air Quality Standards)*
- *RFP (Request for Proposal)*
- *SCR (Selective Catalytic Reduction)*

February 17, 2010

# Kentucky's carbon footprint: Where does it lead?

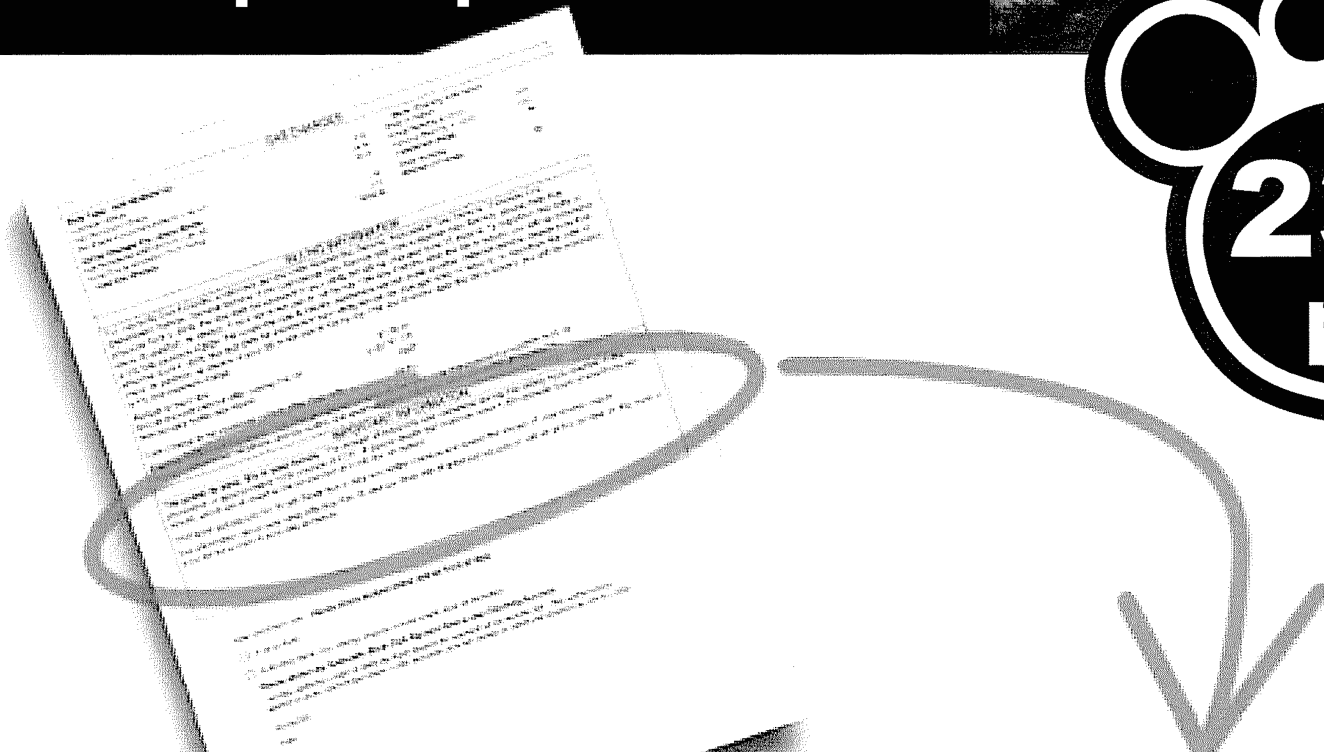
# Tough issues, tough solutions



- Renewable Energy
- Transmission Grid
- Carbon Legislation or EPA Regulation
- Efficient Use of Electricity

LG&E KU

# Carbon footprint is about to leave a deeper impression




## IMPORTANT INFORMATION

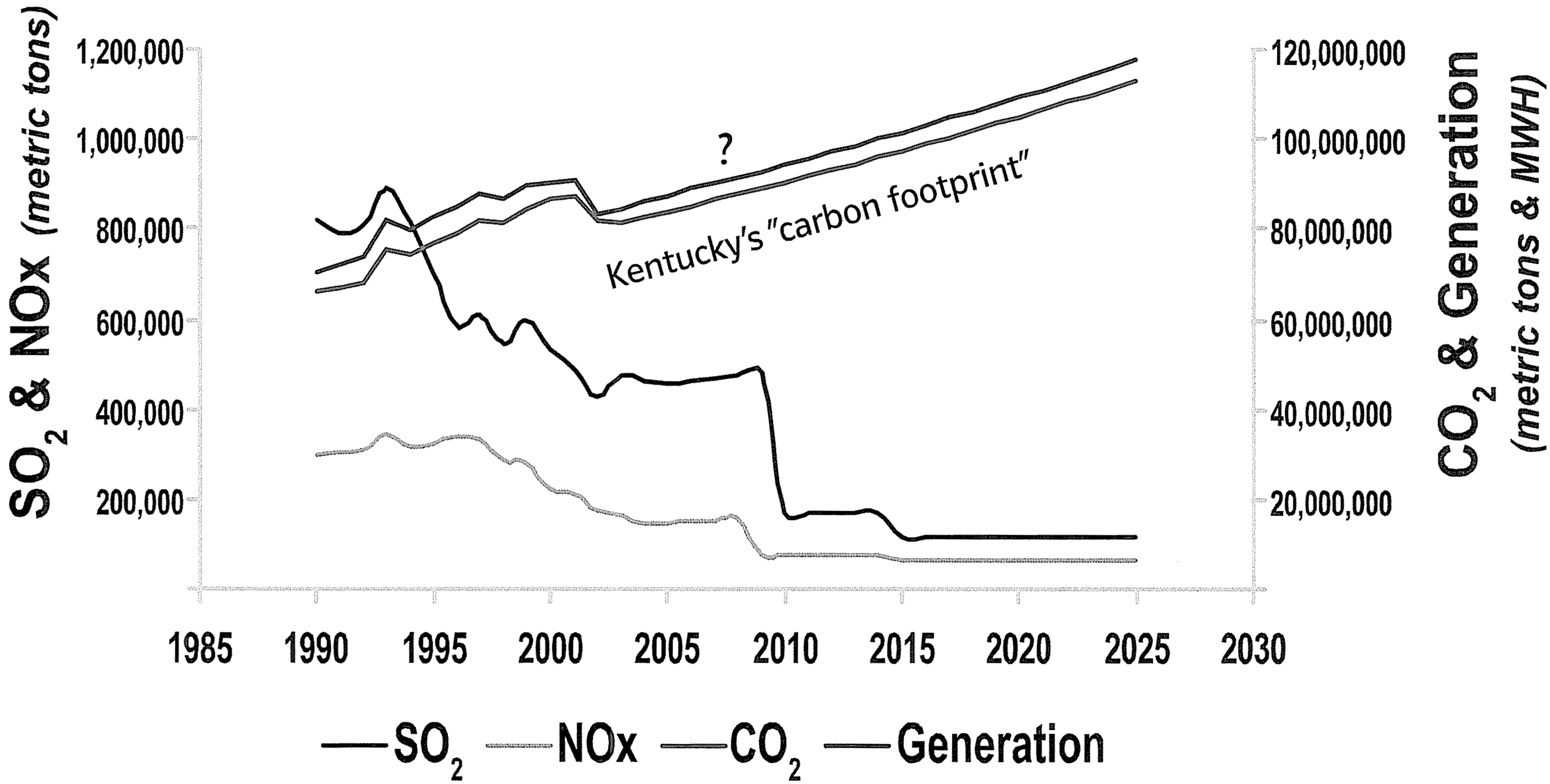
**The power to save. It's in your hands.** The amount of electricity you consumed during this billing cycle resulted in the production of approximately 2350 pounds of CO2.

You can reduce the impact of these emissions by joining our Demand Conservation program, which allows you to help us reduce the need for generating electricity at peak times. Visit our website at www.eon-us.com or call 1-866-356-5467 for more information or to sign up today.

To request a copy of your rate schedule, please call (502) 589-1444.

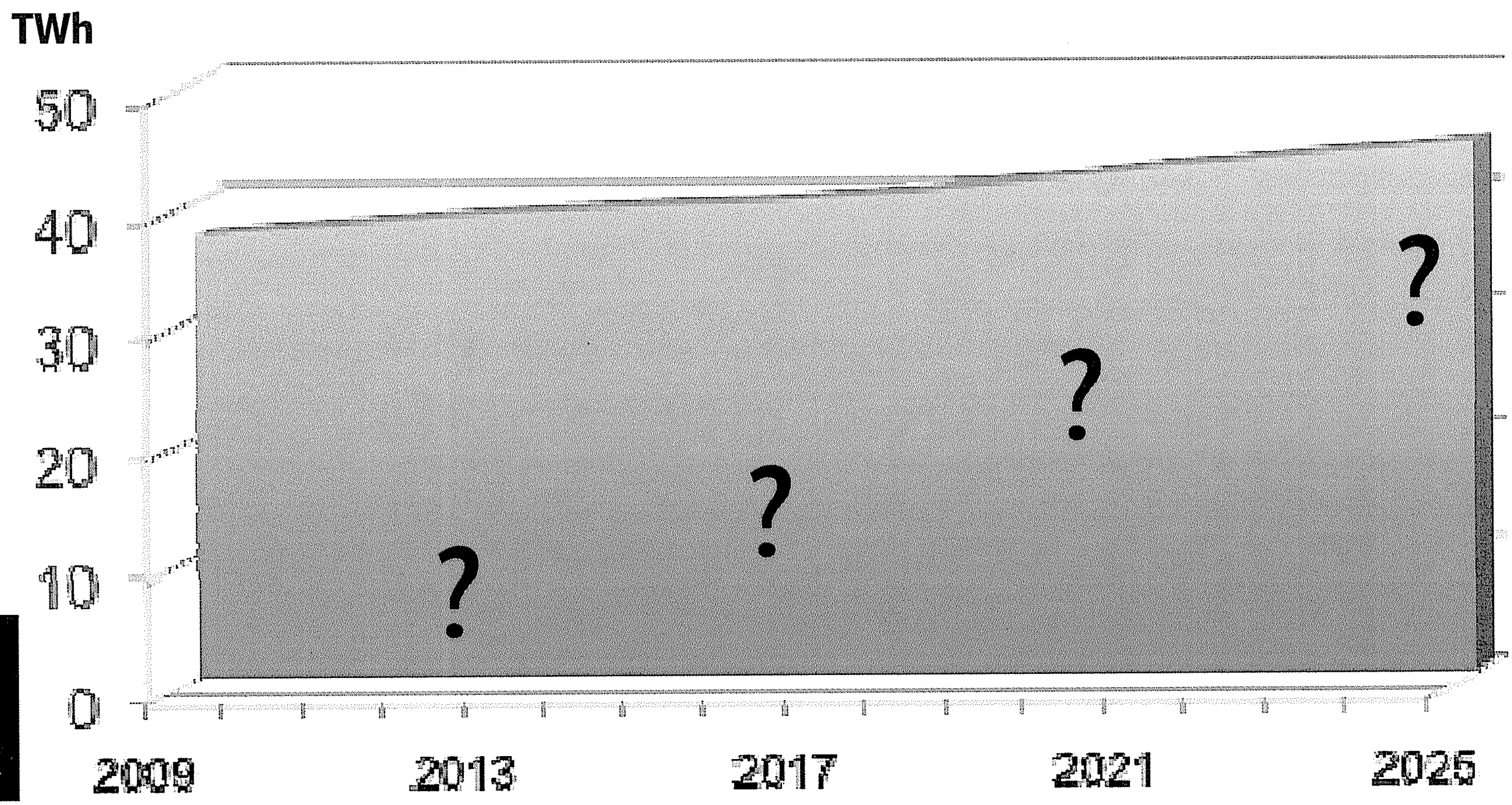
# Past successes, future challenges

## $CO_2$ emissions: **100 times** larger issue than $SO_2$/NOx




Sources: U.S. DOE Energy Information Administration for historic emissions and generation. U.S. EPA for future $SO_2$ and NOx state budgets. In-house projections of generation and $CO_2$ based on 1.5% annual growth. 2007 data.

# Your growth in electric usage


**PROJECTED ELECTRIC DEMAND BY LG&E/KU CUSTOMERS**

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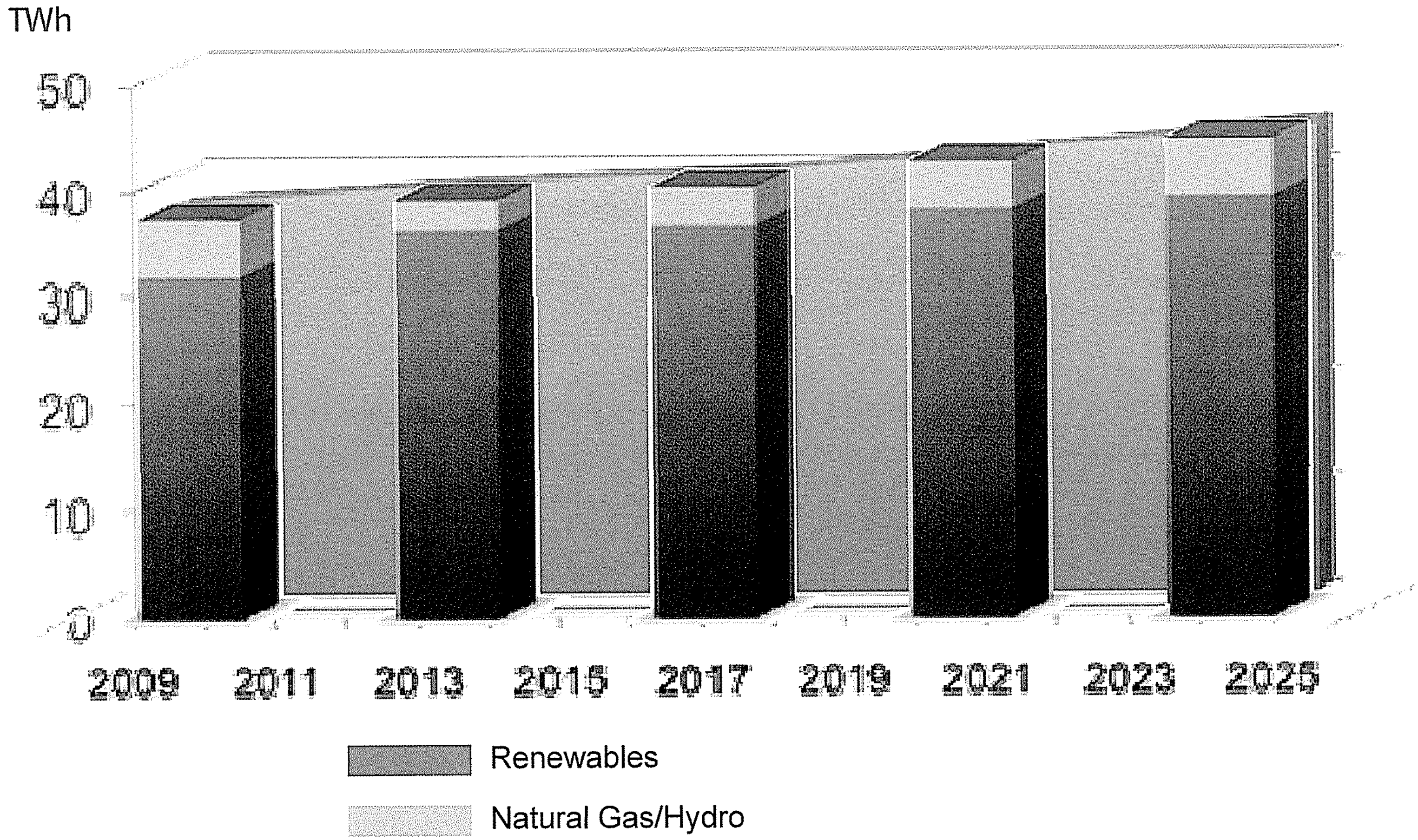
SOURCE: 2008 Integrated Resource Plan

# How we plan to meet your electric demand

## 95% OF THE ELECTRICITY YOU USE COMES FROM COAL-FIRED POWER PLANTS

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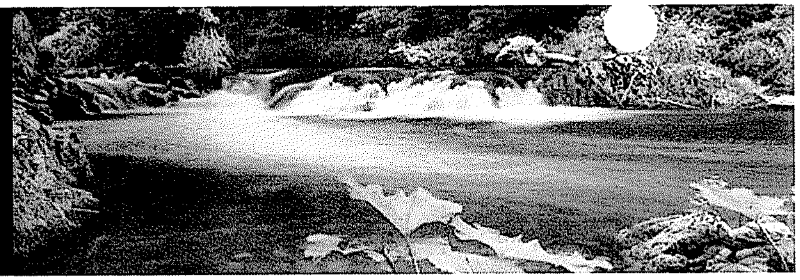
SOURCE: 2008 Integrated Resource Plan

# "Renewable portfolio standards"



**Renewable Portfolio Standards (RPS) should be considered in the context of national or regional greenhouse gas restrictions.**

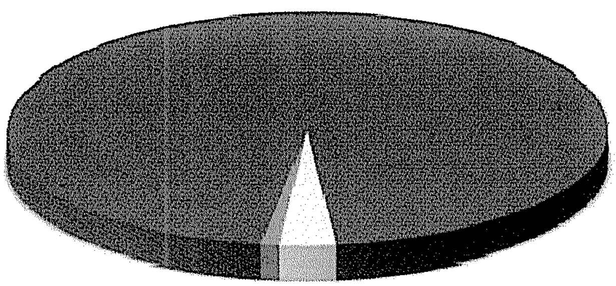
Coal

Natural Gas

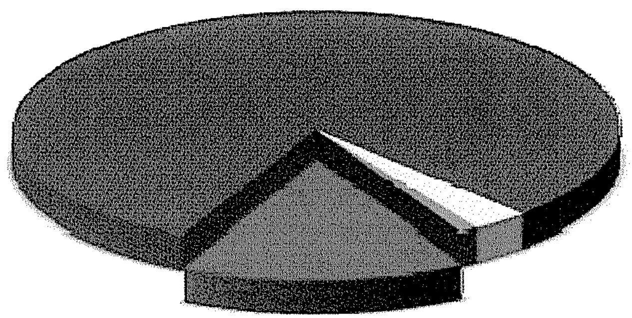
Hydro

Renewables

**Currently Zero Renewables**

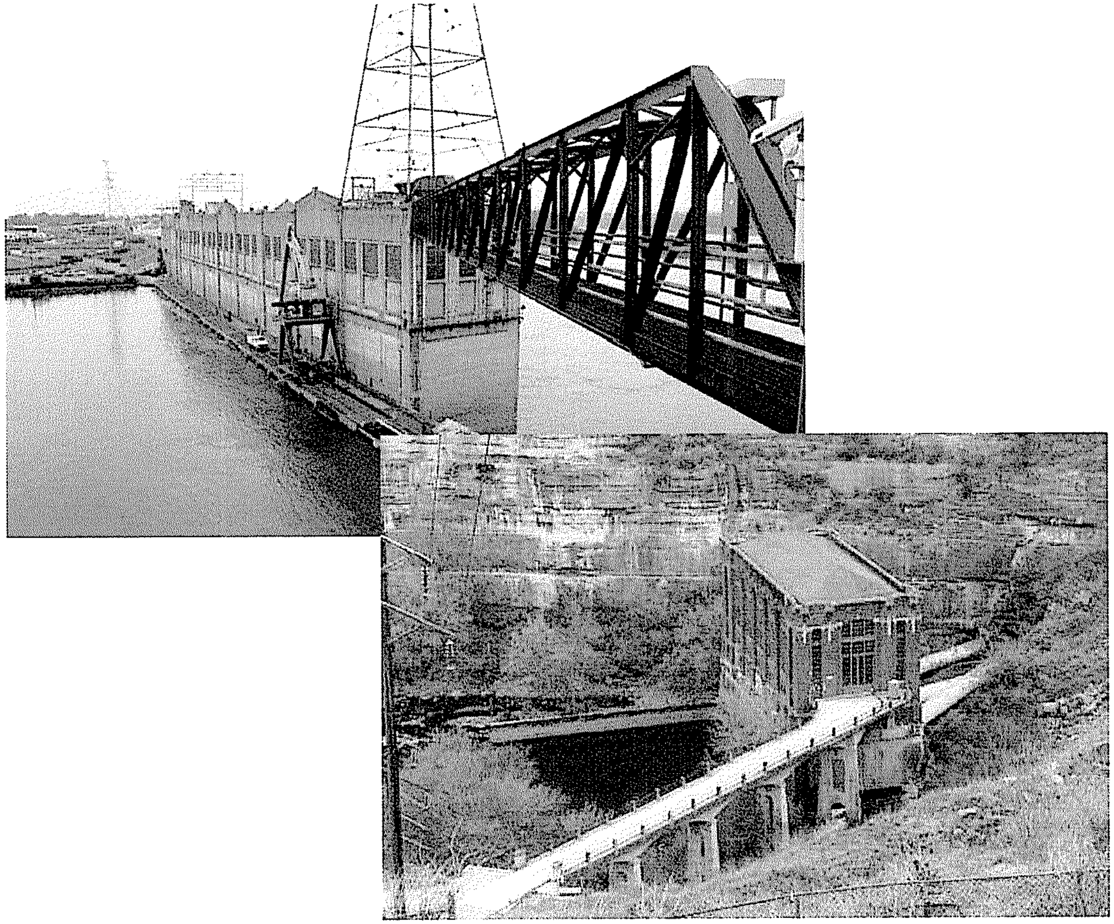


**Under 2020 Federal Proposals**



*Note: Existing hydro does not count toward renewable mandates.*

# Considerations — hydro



- Annual availability equivalent up to 40 percent of continuous maximum capability
- Many legal/regulatory entities involved with different missions — recreation, transportation, nature preserves
- Low operating cost — "no fuel"
- Most hydro locations are already being used

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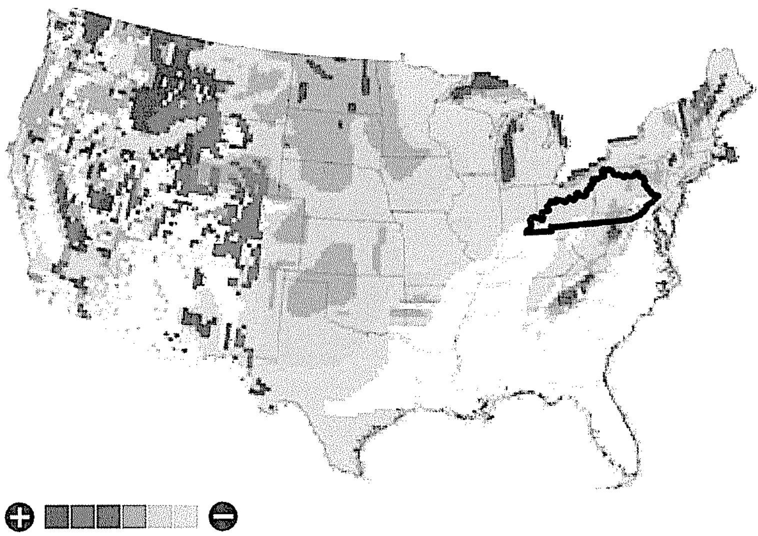
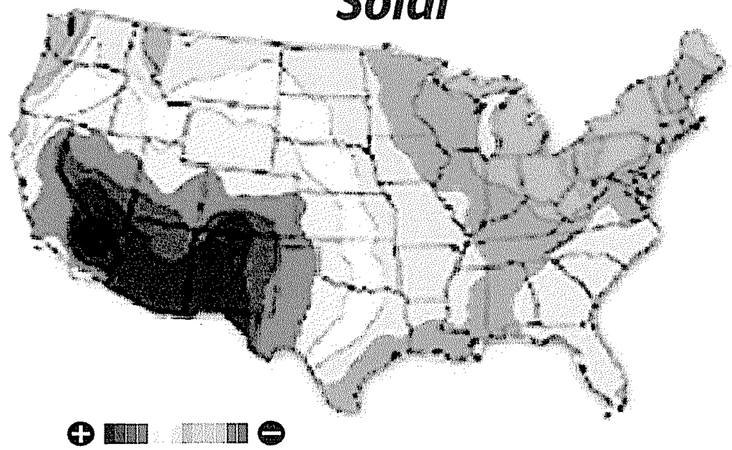
# Considerations — wind, solar and geothermal

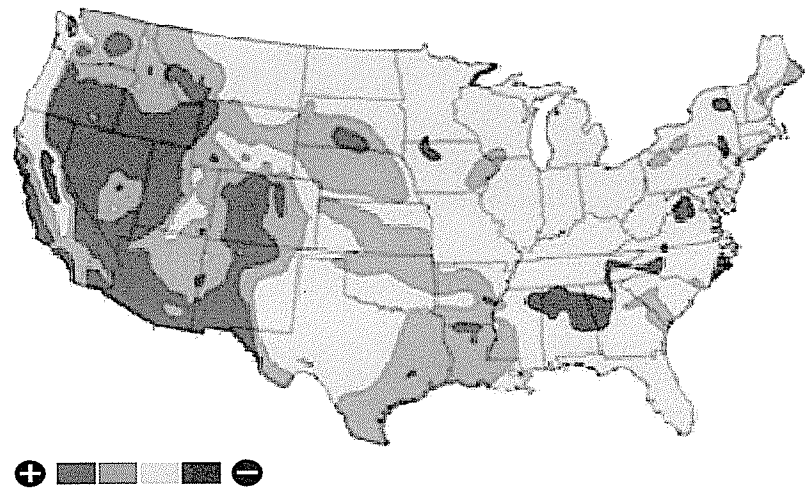
Wind



Solar



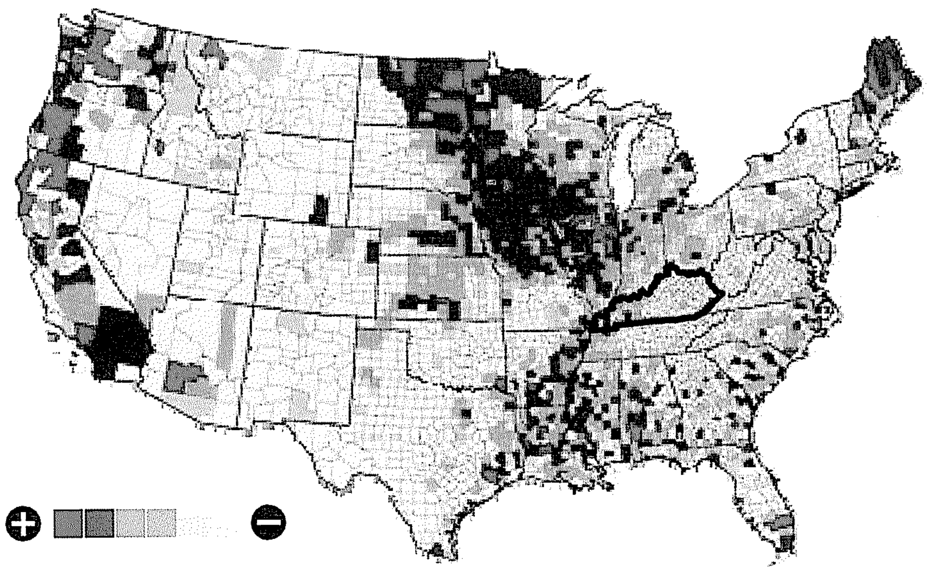
Geothermal



SOURCES: Dept. of Energy
National Renewable Energy Laboratory

# Considerations — biomass

### *Biomass*

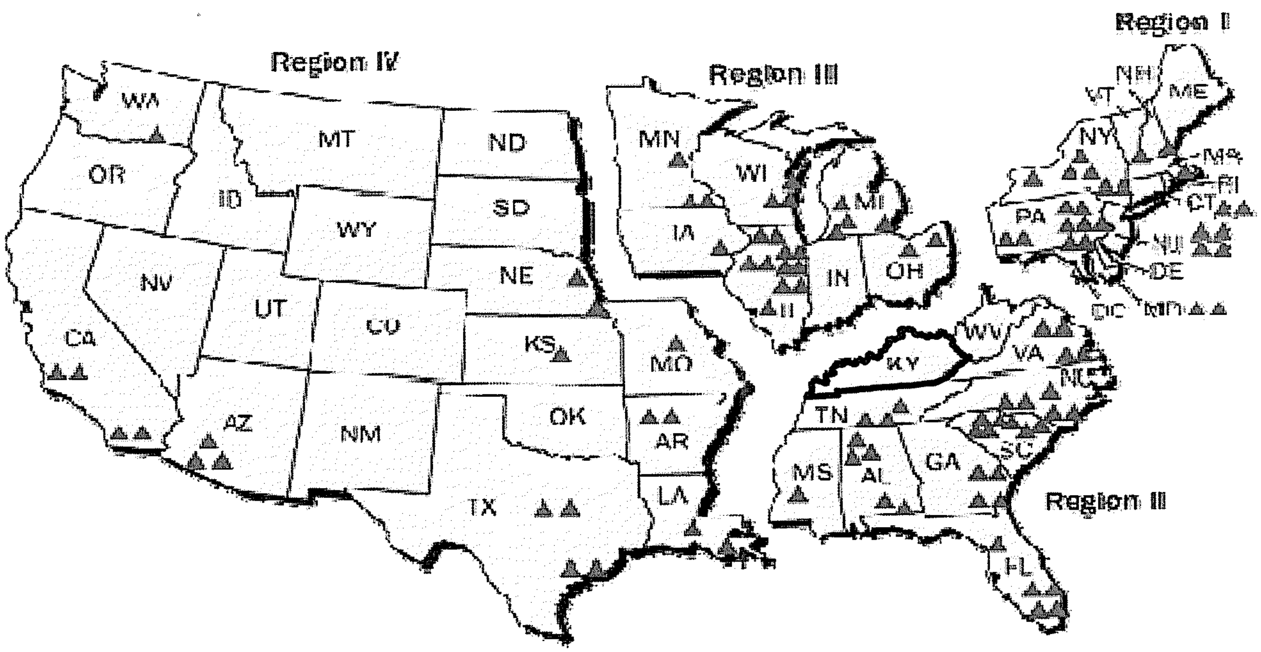


### *Governor's Biomass Task Force*

- Meet RPS requirements with "in-state" resources
- Co-fire biomass with coal
- 15 million tons of biomass combustion for 12% RPS
- Supply infrastructure and sustainability

SOURCES: Dept. of Energy
National Renewable Energy Laboratory

# The nuclear option




**Nuclear plants currently licensed to operate**
SOURCE: Nuclear Regulatory Commission

- Zero-carbon option
- Enormous investment of time and money
- Critical that there be a strong public and political consensus
- Disposal still an issue
- Nuclear is a **potential long-term** solution for Kentucky

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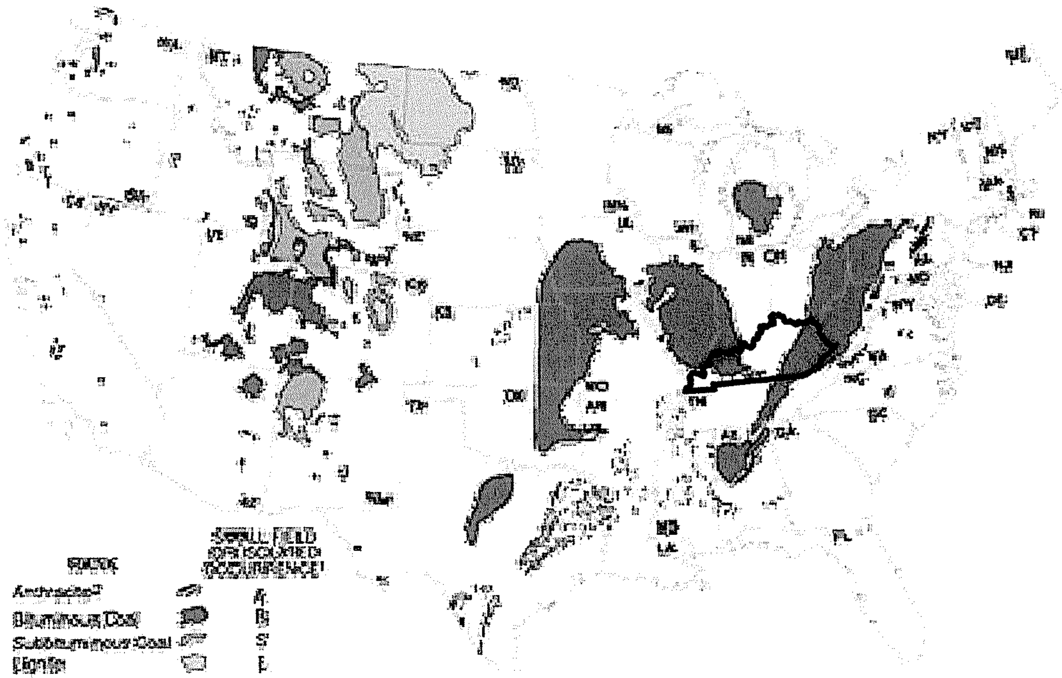
# Considerations — coal



SOURCE: Dept. of Energy

- One of the most widely-used fuels for electrical generation — 90% availability
- 50% of U.S. power produced today
- 95% of Ky. power produced today
- One of the largest fixed-source producers of $CO_2$
- Relatively low transportation costs (river barge)

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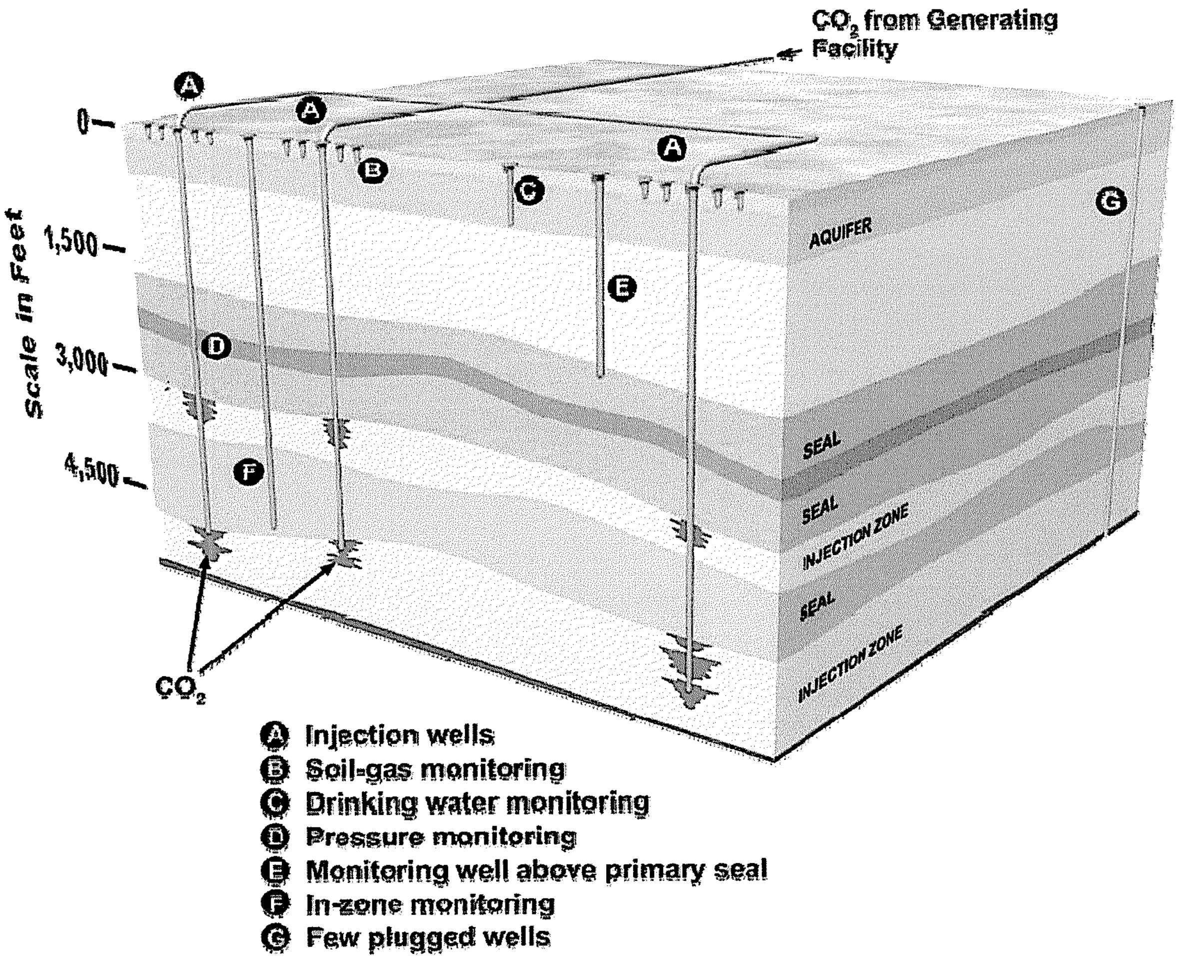
# Carbon capture & sequestration




*What's involved….*

- "Bury" the problem
- Deep underground wells — depleted oil fields
- Significant investments in new technology, pumping systems
- Promising option, but no large-scale commercial application yet
- "NUMBY"

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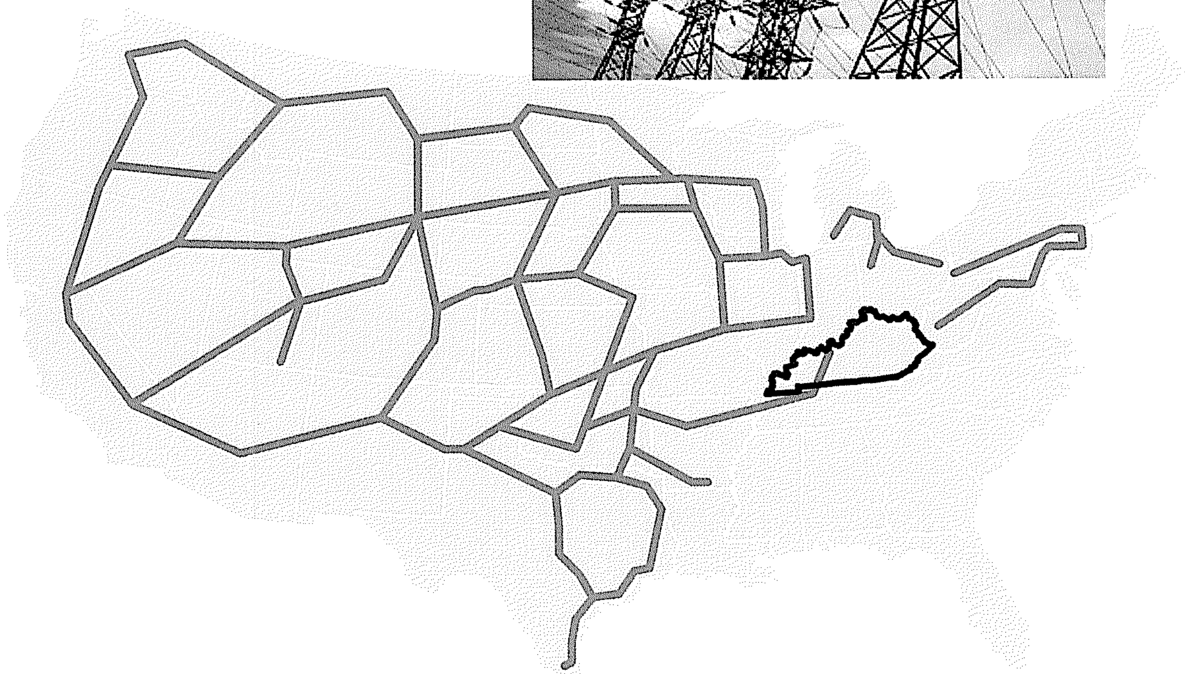
SOURCE: FutureGen Alliance

# If we can't make it, why not just *move* it?

*"Costs" of transmission...*

- Current grid is stretched — would require major new construction at large capital cost
- Risks of over-reliance on single highway (Canadian blackout)
- Development/approval time
- NIMBY



**Transmission grid system needed to support new renewable power development**

SOURCE: Dept. of Energy
National Renewable Energy Laboratory

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# Carbon legislation or EPA regulation

Carefully crafted, comprehensive legislation is a more effective option for controlling greenhouse gas emissions than piece-meal EPA regulation

## Legislation should:

- Cover economy-wide entities
- Provide larger initial allowance allocations and longer phase-out period to ease transition
- Begin with an effective safety valve allowance price

## EPA regulation via the Clean Air Act would:

- Utilize low threshold levels for applicable entities
- Establish a significant number of non-attainment areas
- Regulate an extremely high-volume pollutant with no commercial control technology available

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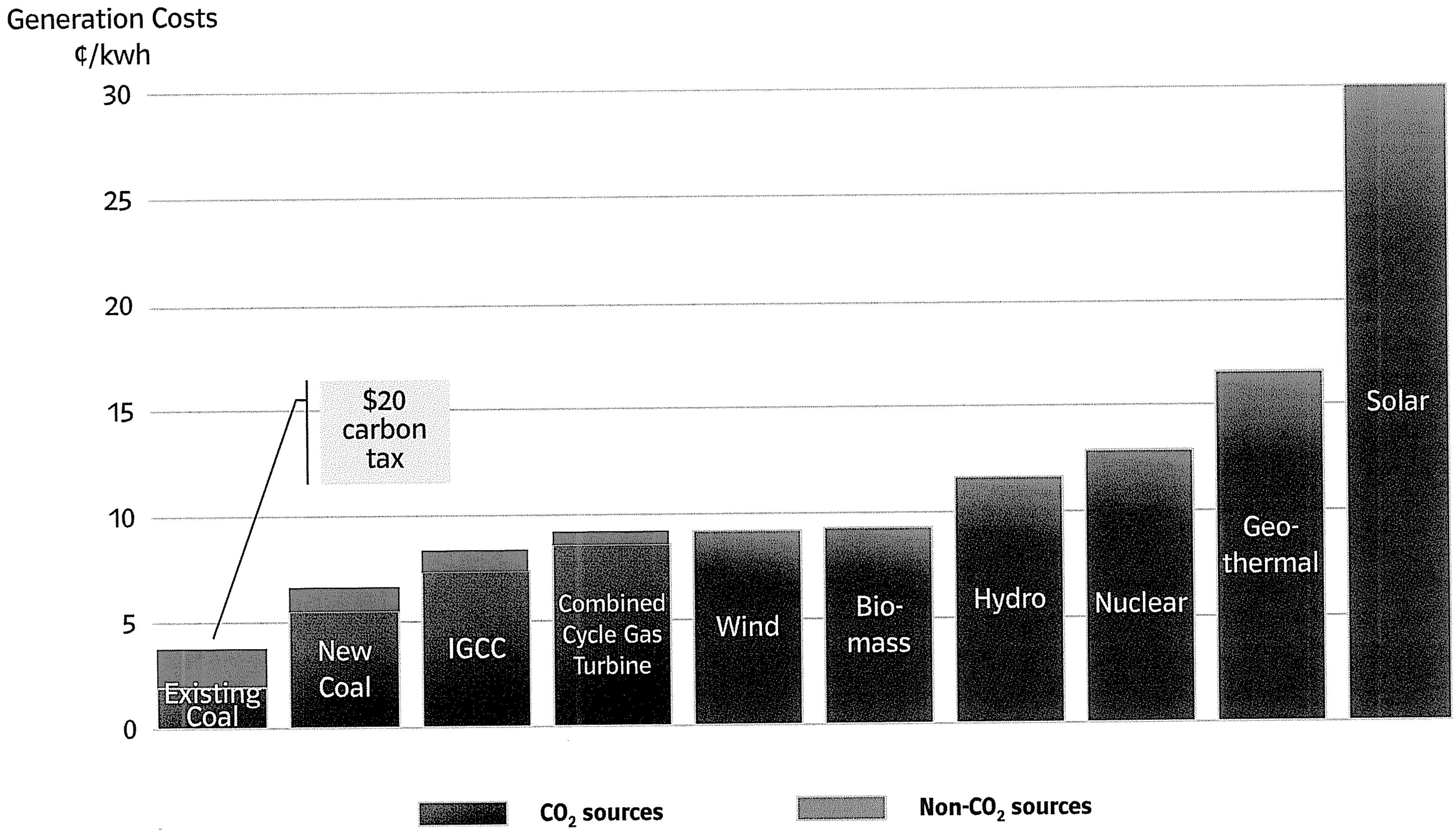
# Cost Comparison

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# American Clean Energy and Security Act of 2009

- Passed House on June 26, 2009.
- Mandates a 17 percent reduction in greenhouse gases by 2020 and 83 percent by 2050 from 2005 levels.
- Senate did not advance similar bill.
- Current form contains elements that are a step in the right direction.
- Copenhagen commitments were based on the House bill targets.

*To further mitigate costs to our customers, additional elements E.ON U.S. would like to see included in the bill are:*

- Modified near- and mid-term greenhouse gas reduction targets and timetables.
- Inclusion of a price "ceiling" on emission allowance costs.
- Extension of the phase-out period for the allocation of allowances.
- Preempt inappropriate EPA regulation under the CAA .

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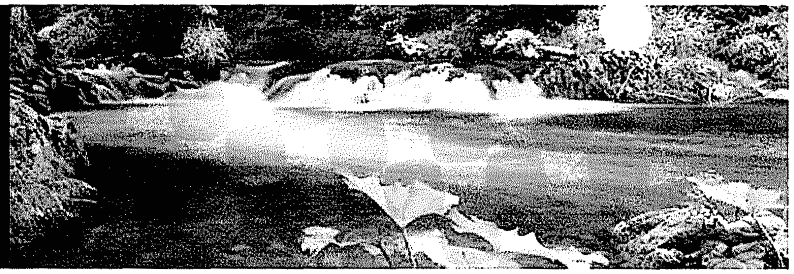
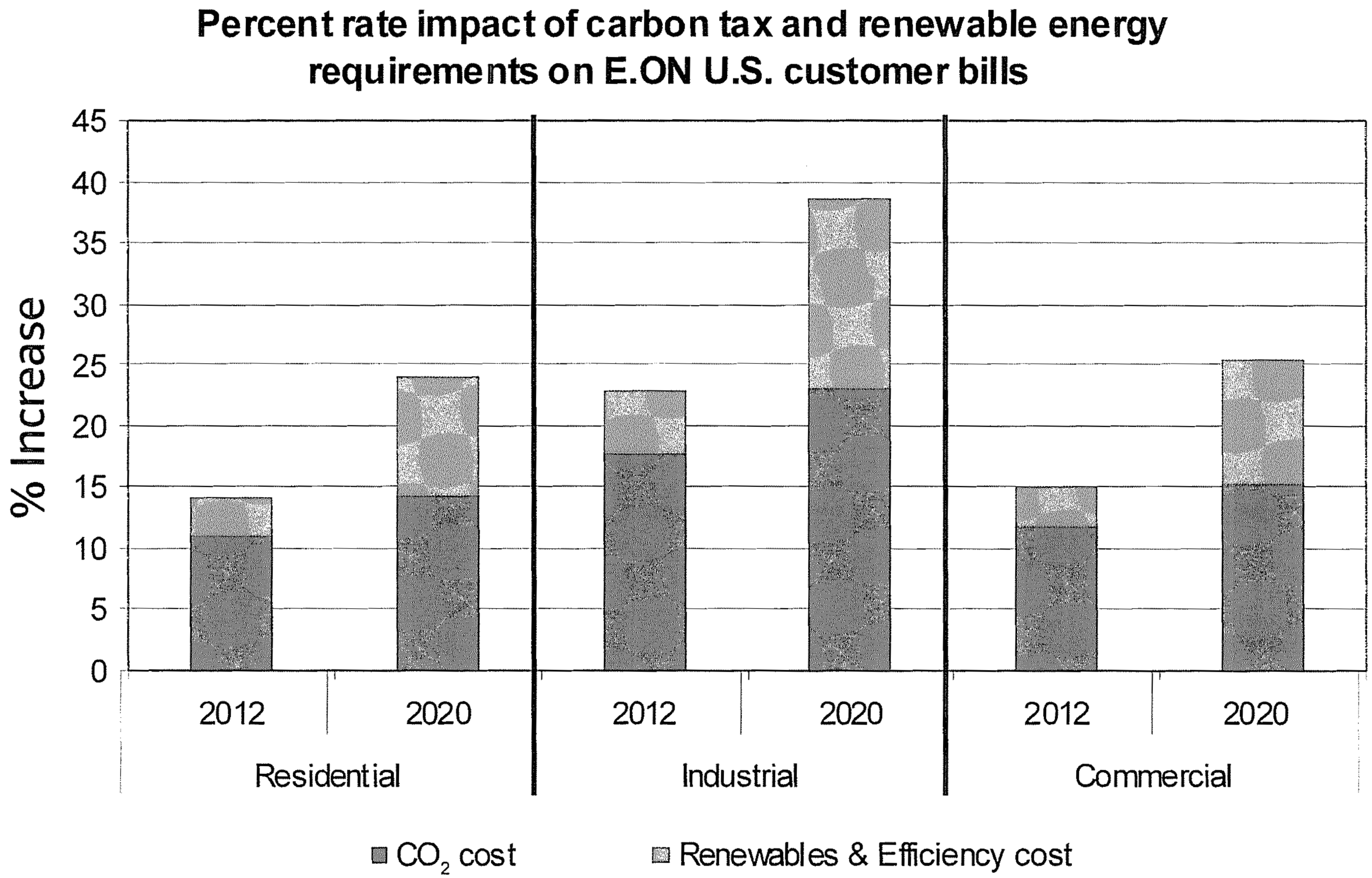
# Estimated costs






- Percentage increases calculated using 2008 rates applied to 2020 projected sales
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- Assumes utilities meet the CERES target entirely through purchase of Alternative Compliance Payments (ACPs) set in the bill at 2.5 cents per KWH in 2010 (and subsequently indexed).

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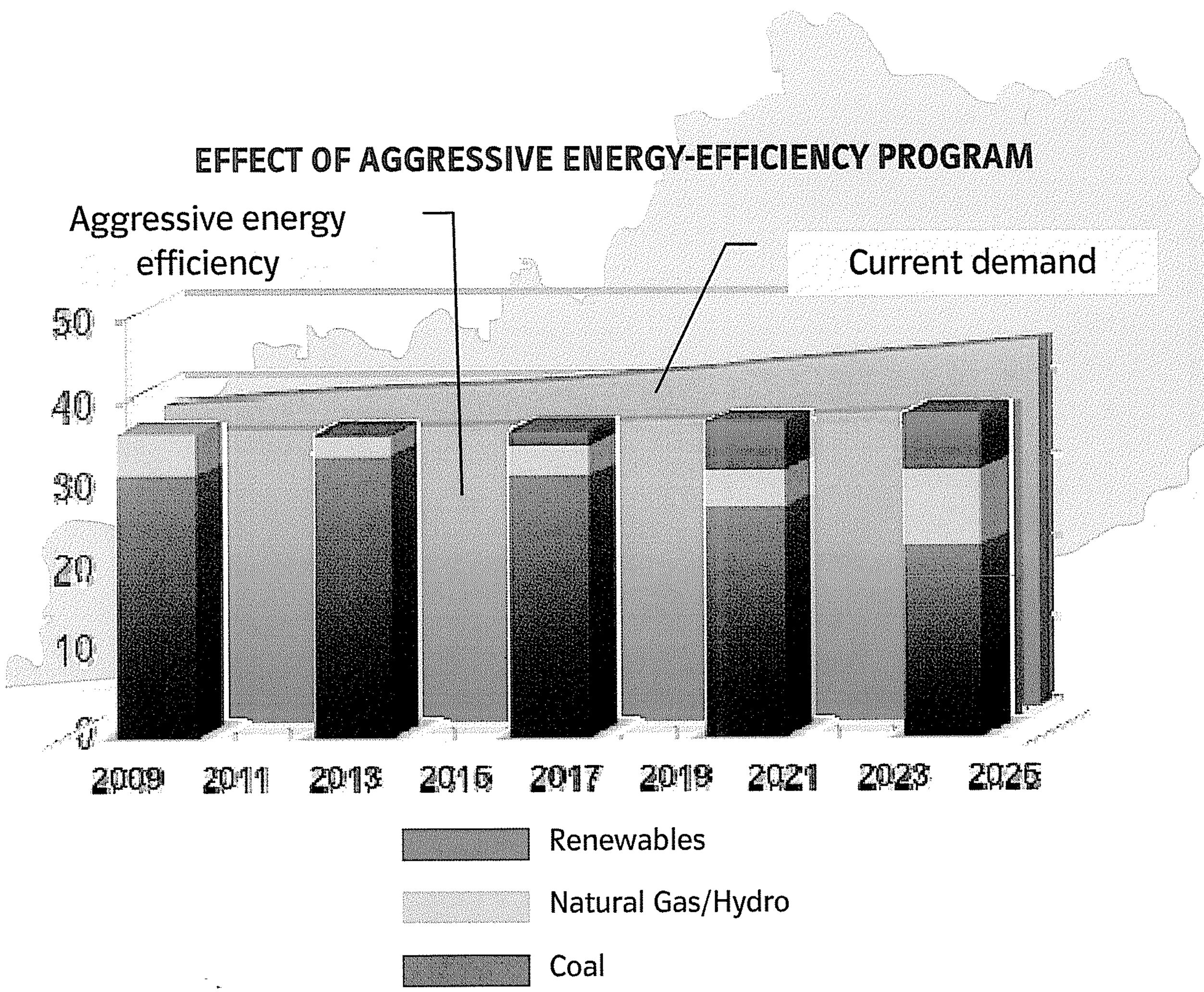
# Reducing demand — the challenge




*What it would take…*

- 15+% reduction in demand
- Unprecedented consumer commitment to energy efficiency
- Commitment to "smart grid"
- Less coal in total generation mix, less exposure to carbon tax, but high cost of purchased or developed renewable power sources

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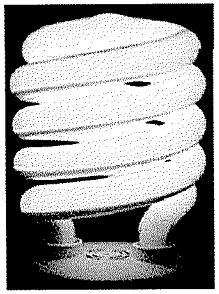
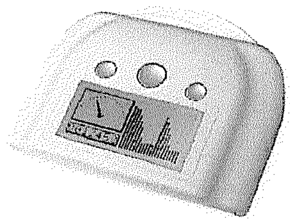
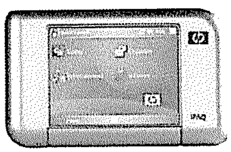
SOURCE: 2008 Integrated Resource Plan

# Energy Efficiency Initiatives







- E.ON U.S. is investing more than $25 million in energy efficiency programs annually — at least $182 million over the life of the program

  Examples:
  - Enhanced energy audits
  - Commercial rebates
  - Residential lighting

- Expected to reduce the need for additional generation by more than 500 megawatts

- Conserve Energy During Heavy Demand
  - Load control program: partnership with customers that allows us to cycle off AC units during peak demand
  - Smart meter pilot program: helps customers manage their usage

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# What are "the next steps?"

- Understand that rising energy costs will be a way of life for years to come — consider everything you do with that in mind
- Make major, sustained commitment to energy efficiency
- E.ON U.S. — to address issues of carbon capture and sequestration with help of policy-makers
- E.ON U.S. — share information and work constructively with policy-makers


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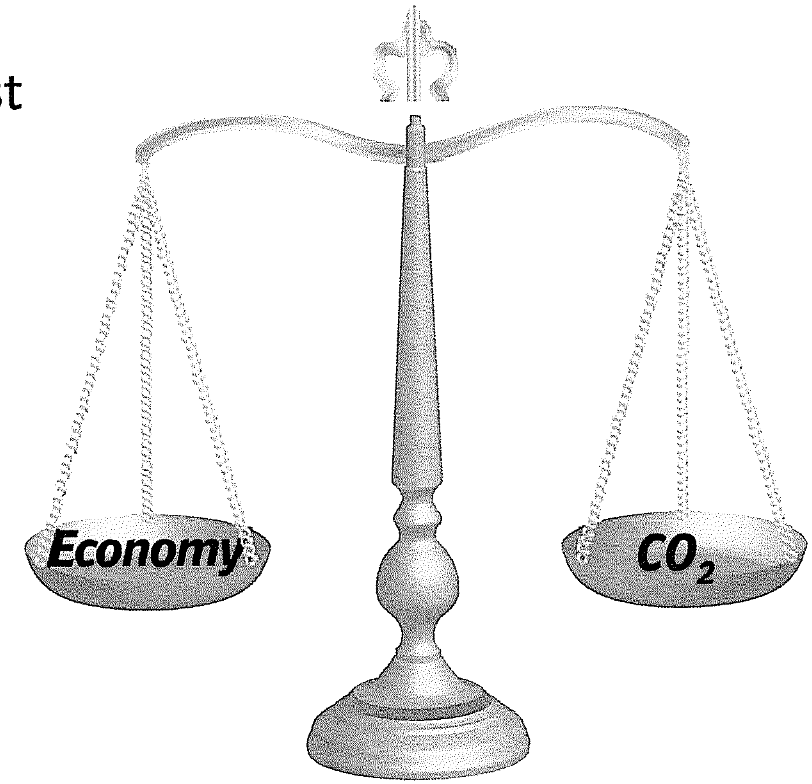
# Balanced Outcome

- Insist on a thorough evaluation of cost
- Allow technology to catch up
- Demand an equitable allocation of carbon credits
- Be efficient — seek incentives for efficiencies




*"To build may have to be the slow and laborious task of years. To destroy can be the thoughtless act of a single day."*

**— Winston Churchill**

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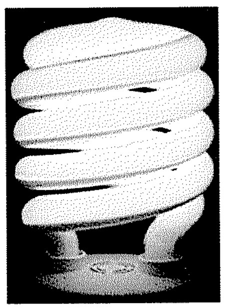
July 14, 2009
Kentucky's carbon footprint:
Where does it lead?

# Tough issues, tough solutions

- *Renewable Energy*
- *Carbon Tax (or Cap and Trade)*
- *Transmission Grid*
- *Efficient Use of Electricity*



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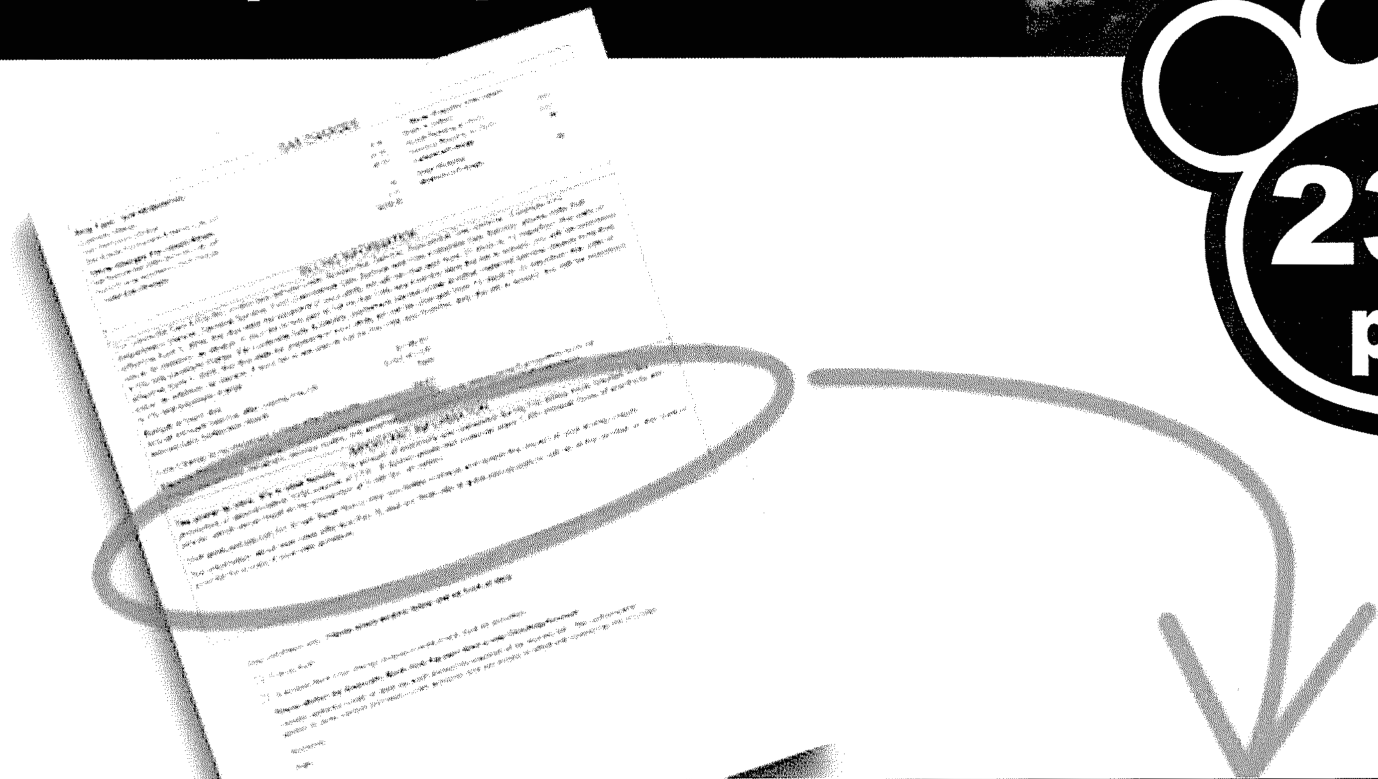

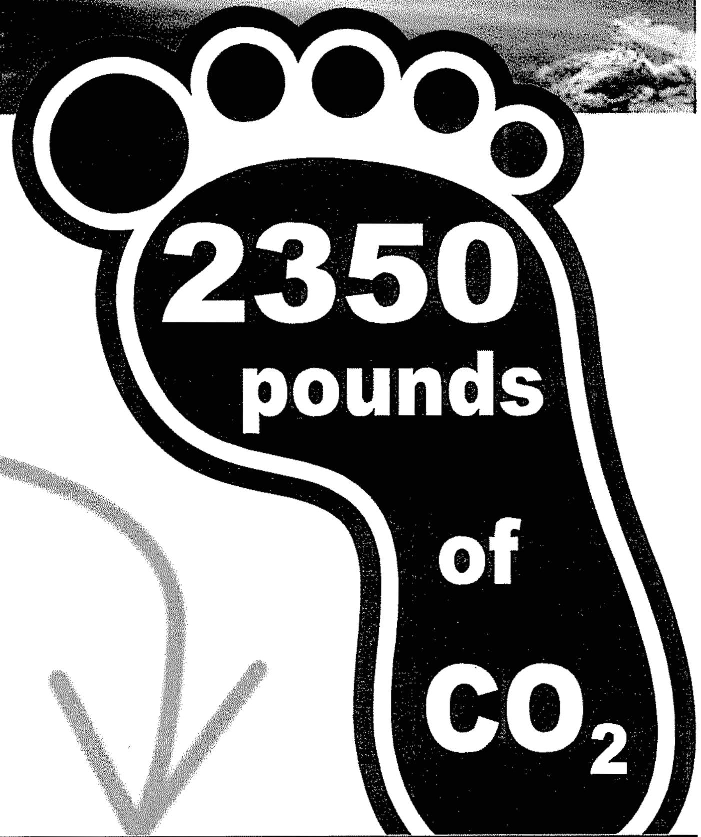


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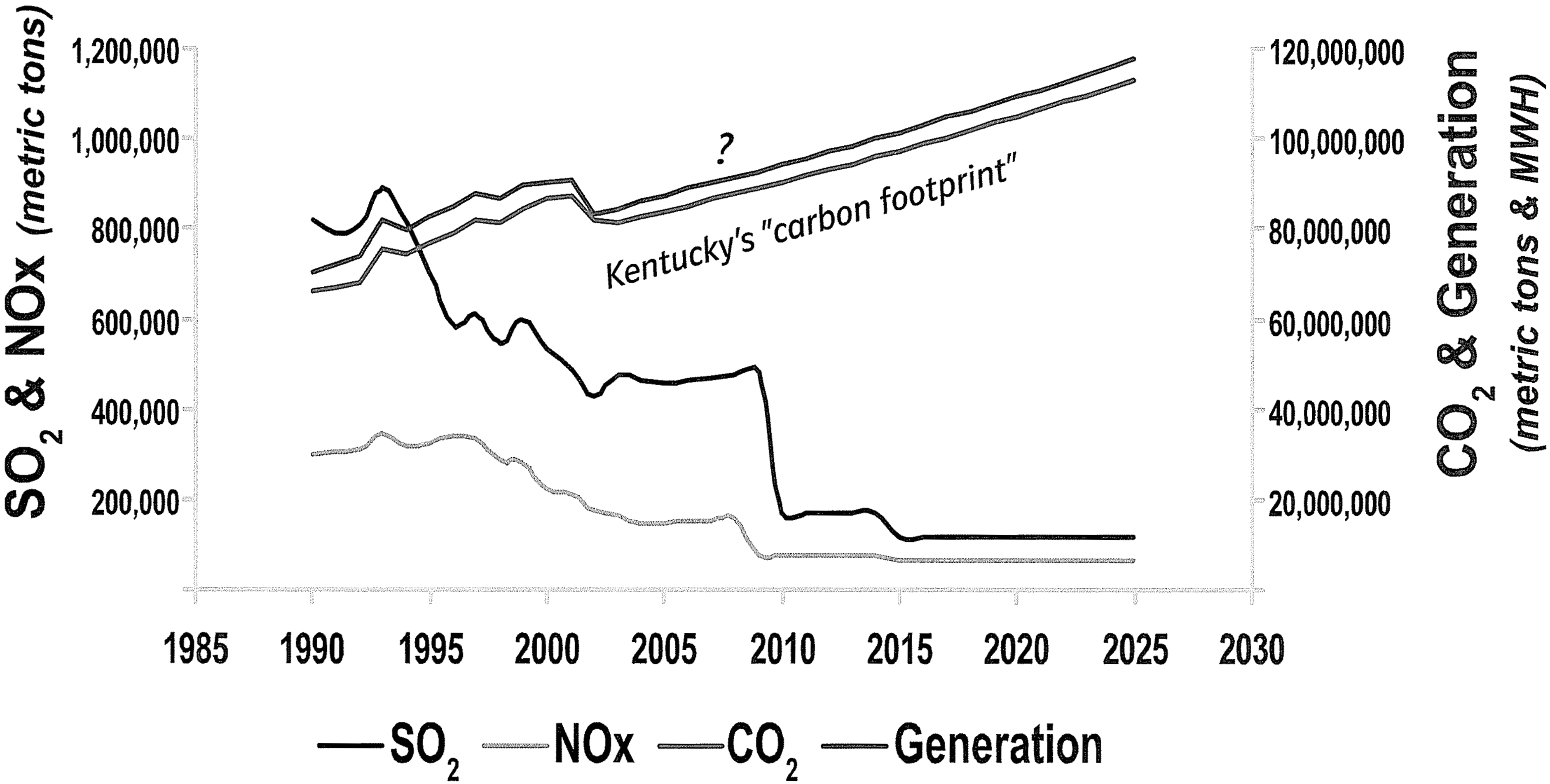
# Past successes, future challenges

## $CO_2$ emissions: **100 times** larger issue than $SO_2$/NOx

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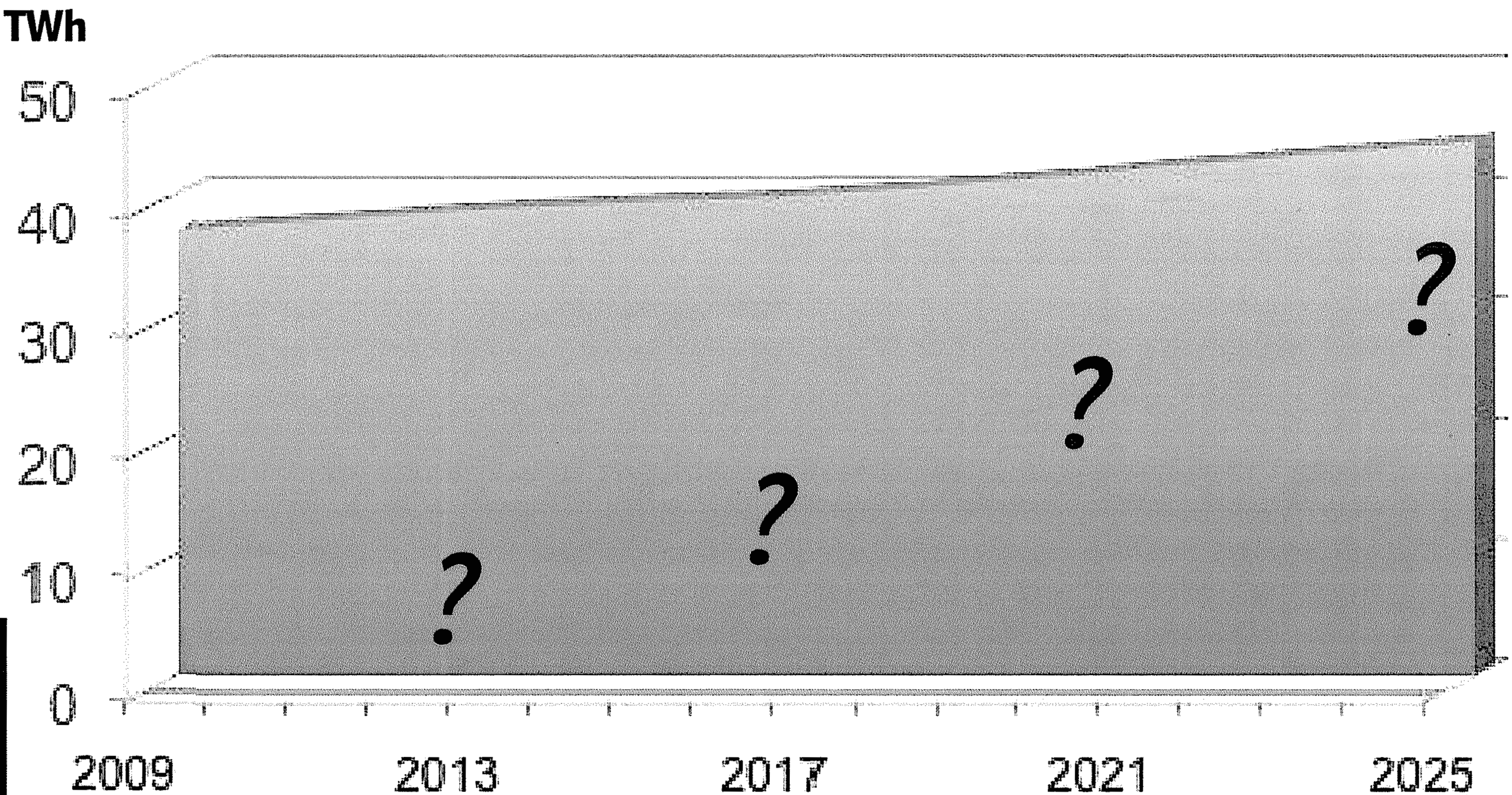
# Your growth in electric usage

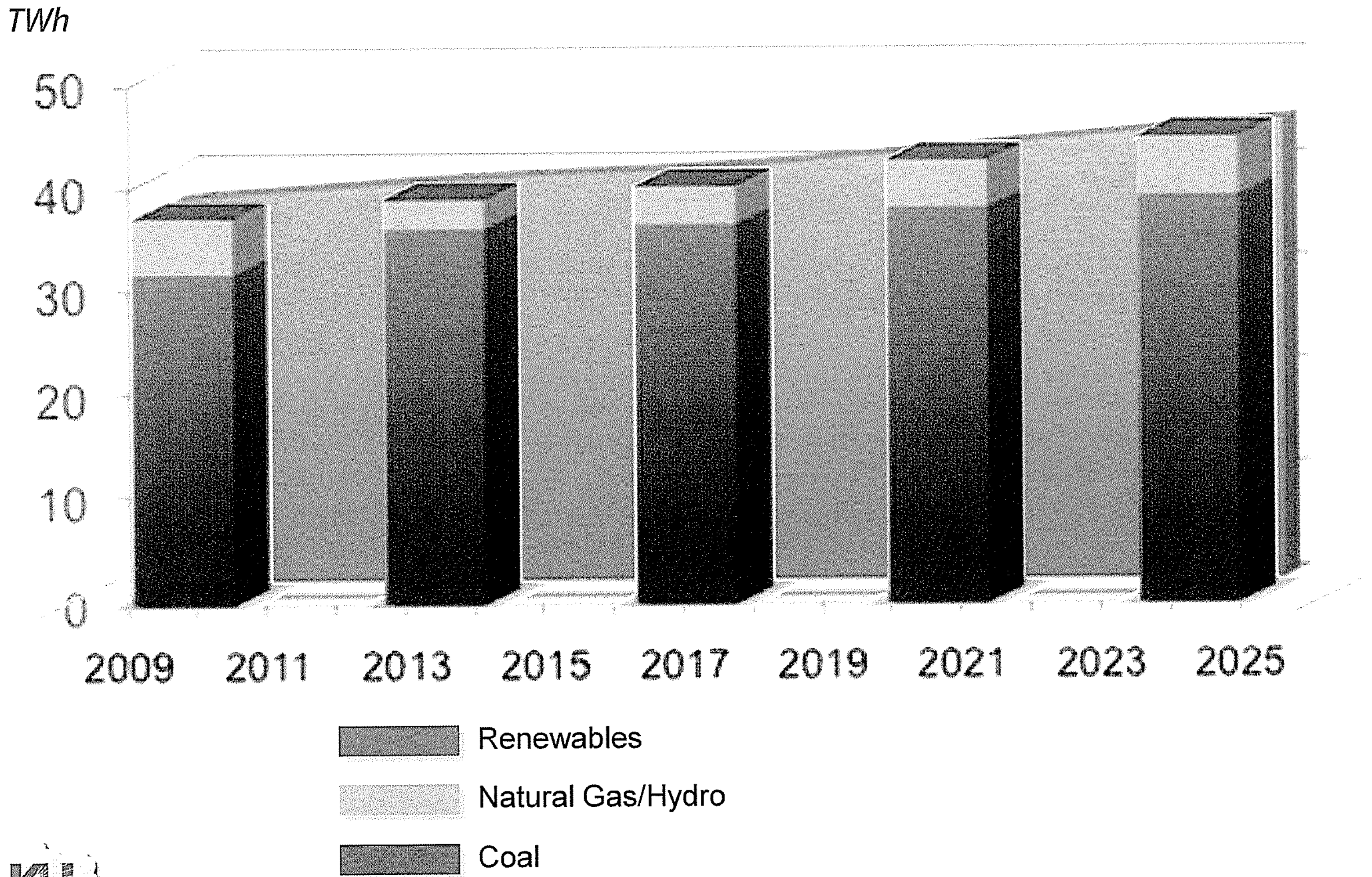




**PROJECTED ELECTRIC DEMAND BY LG&E/KU CUSTOMERS**

*SOURCE: 2008 Integrated Resource Plan*

# How we plan to meet your electric demand

## 95% OF THE ELECTRICITY YOU USE COMES FROM COAL-FIRED POWER PLANTS

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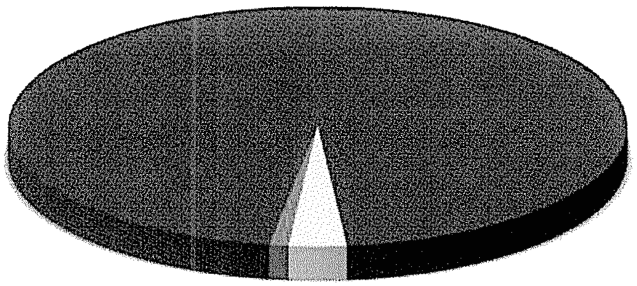
*SOURCE: 2008 Integrated Resource Plan*

# "Renewable portfolio standards"

Currently Zero Renewables

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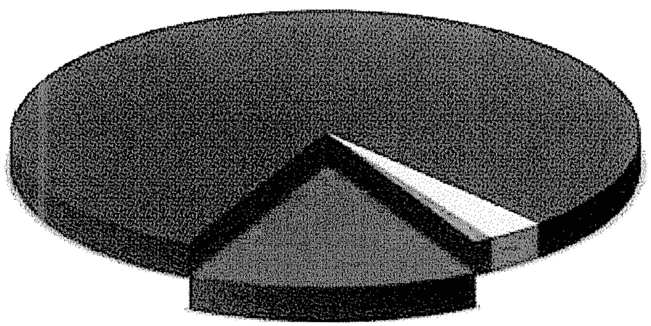
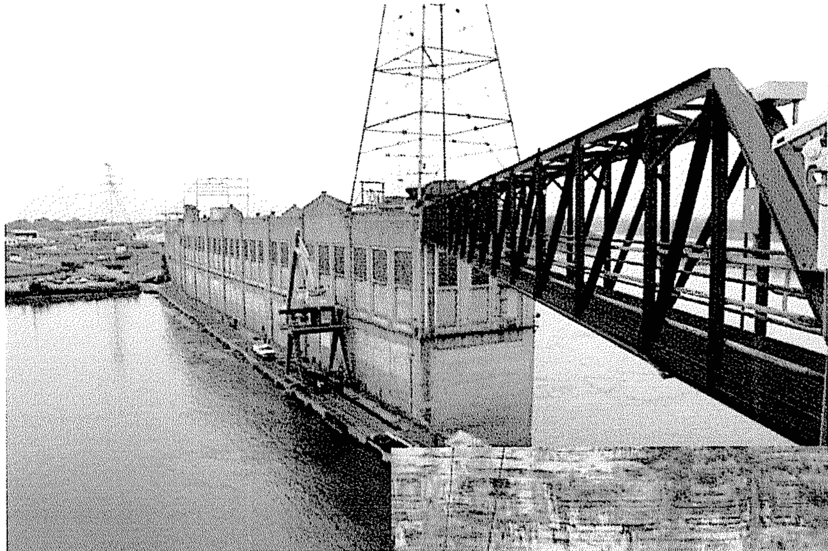
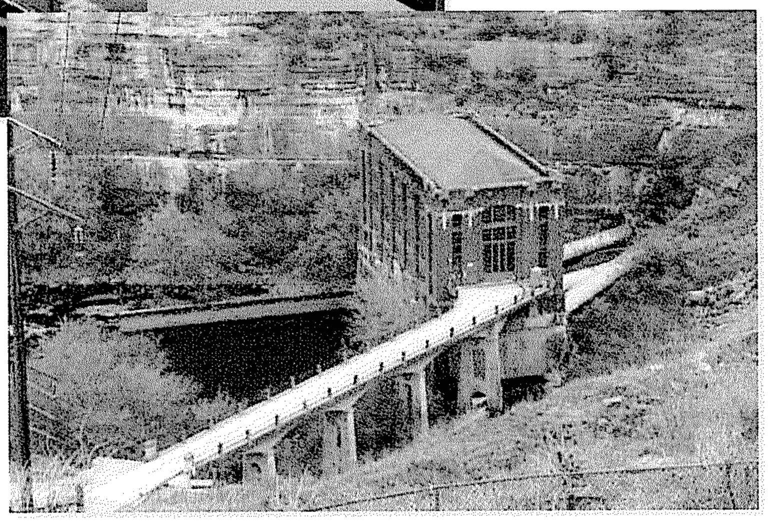


*Note: Existing hydro does not count toward renewable mandates.*

# Considerations — hydro





*Annual availability equivalent up to 40 percent of continuous maximum capability*

*Many legal/regulatory entities involved with different missions - recreation, transportation, nature preserves*

*Low operating cost — "no fuel"*

*Most hydro locations are already being used*

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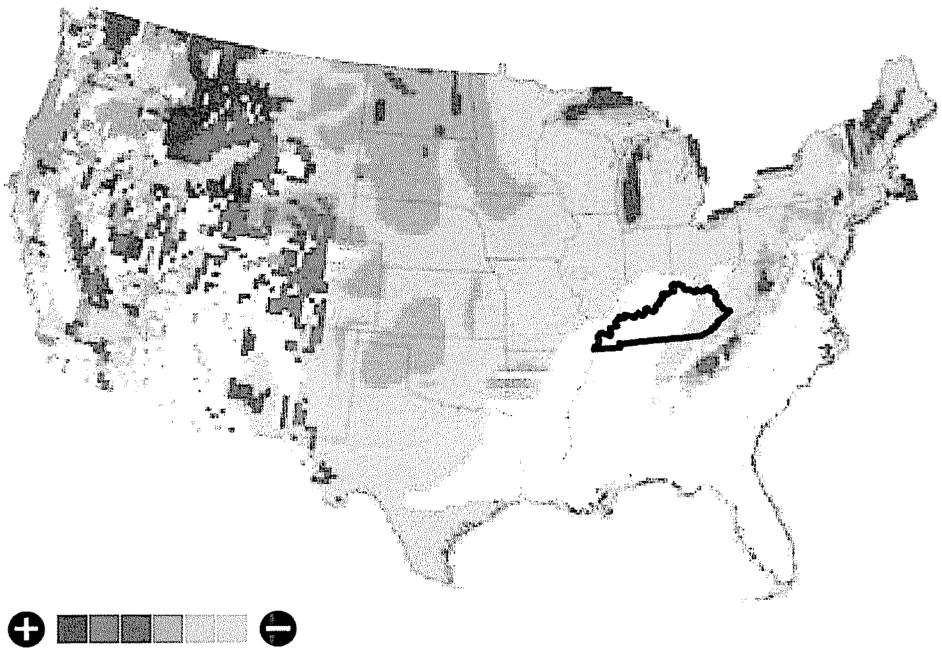
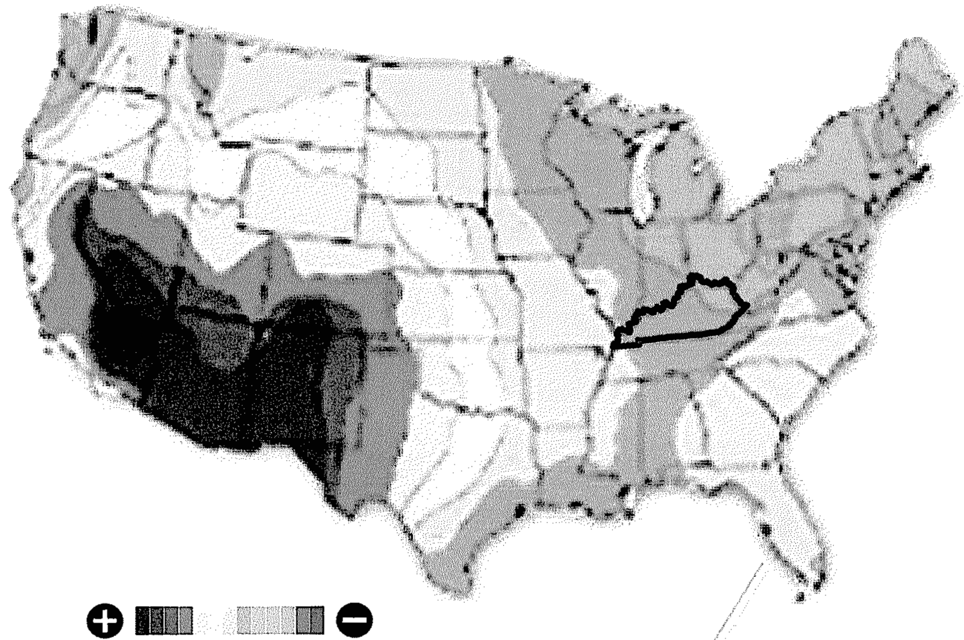
# Considerations — wind and solar

## *Wind*



## *Solar*

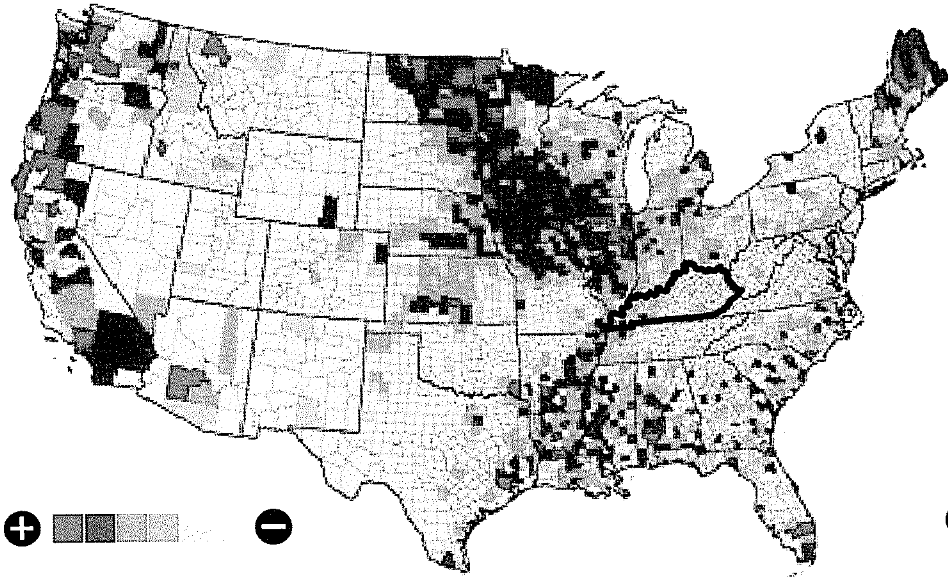


*Why not Florida?*
*Frequent afternoon*
*thunderstorms*

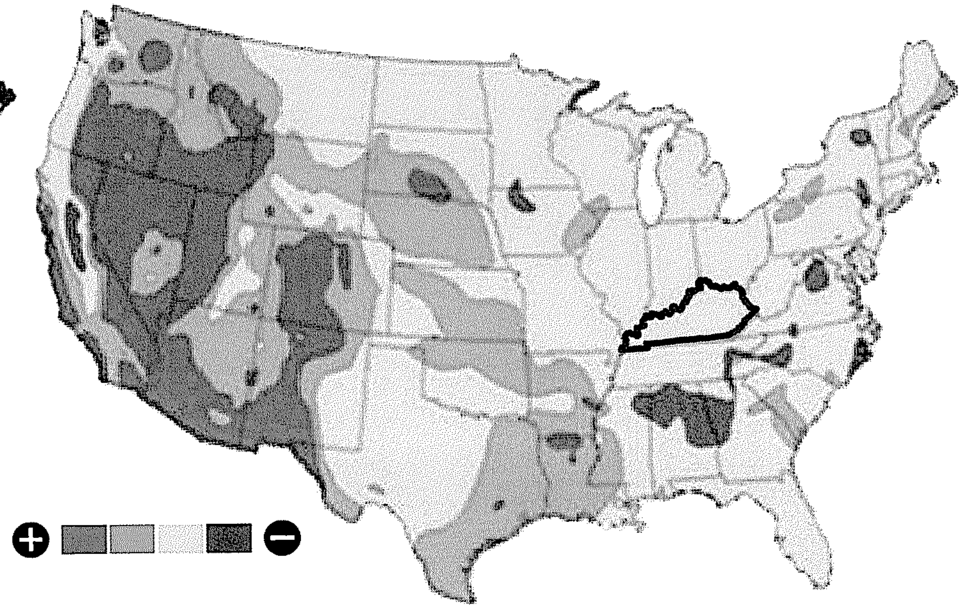
*SOURCES: Dept. of Energy*
*National Renewable Energy Laboratory*

# Considerations — biomass and geothermal

## *Biomass*

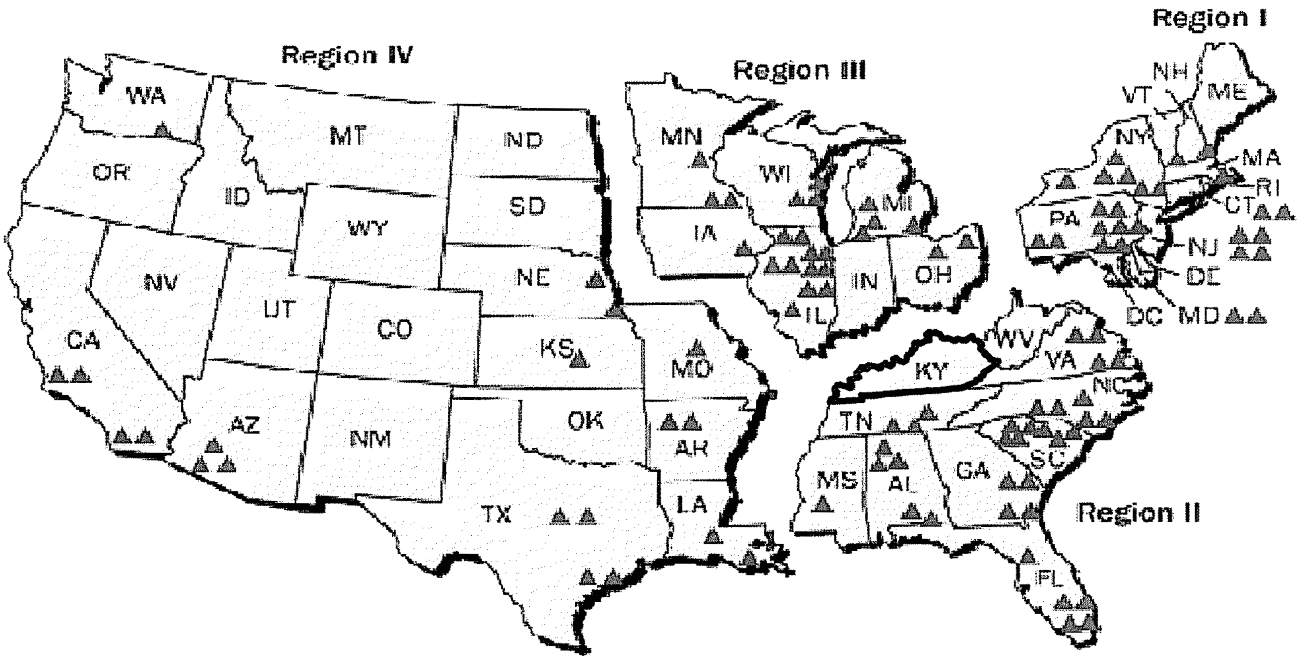


## *Geothermal*



*SOURCES: Dept. of Energy*
*National Renewable Energy Laboratory*

# The nuclear option




**Nuclear plants currently licensed to operate**
*SOURCE: Nuclear Regulatory Commission*

*Zero-carbon option*

*Enormous investment of time and money*

*Critical that there be a strong public and political consensus*

*Disposal still an issue*

*Nuclear currently prohibited in Ky.*

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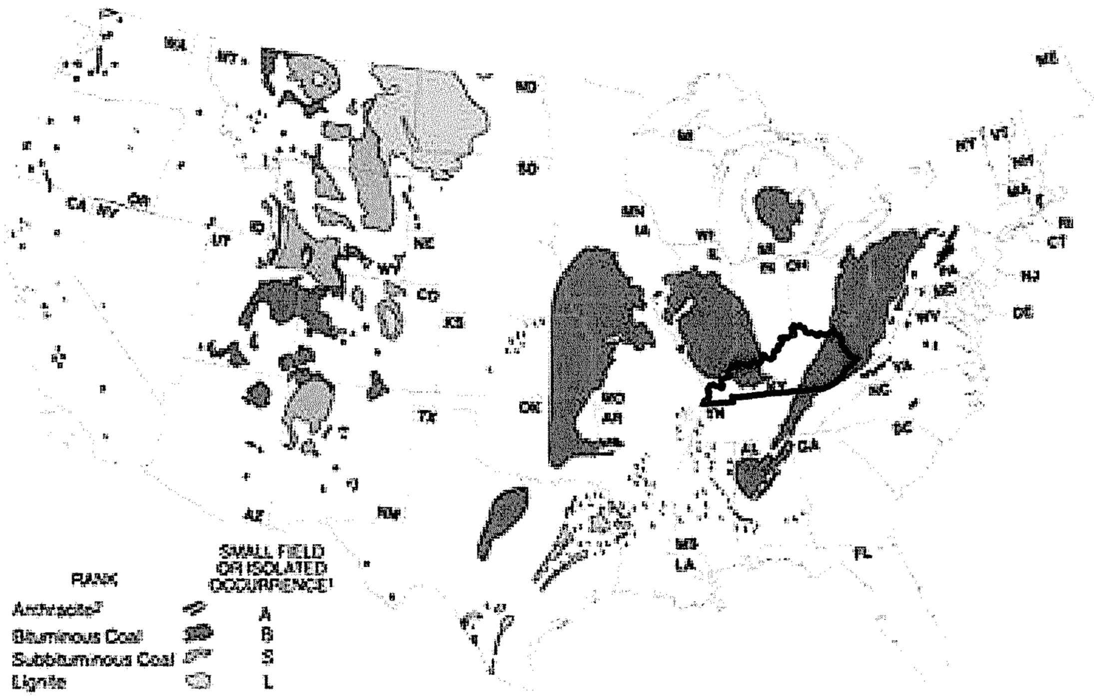
# Considerations — coal

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*One of the most widely-used fuels for electrical generation —90% availability*

*50% of U.S. power produced today*

*95% of Ky. power produced today*

*One of the largest fixed-source producers of $CO_2$*

*Relatively low transportation costs (river barge)*

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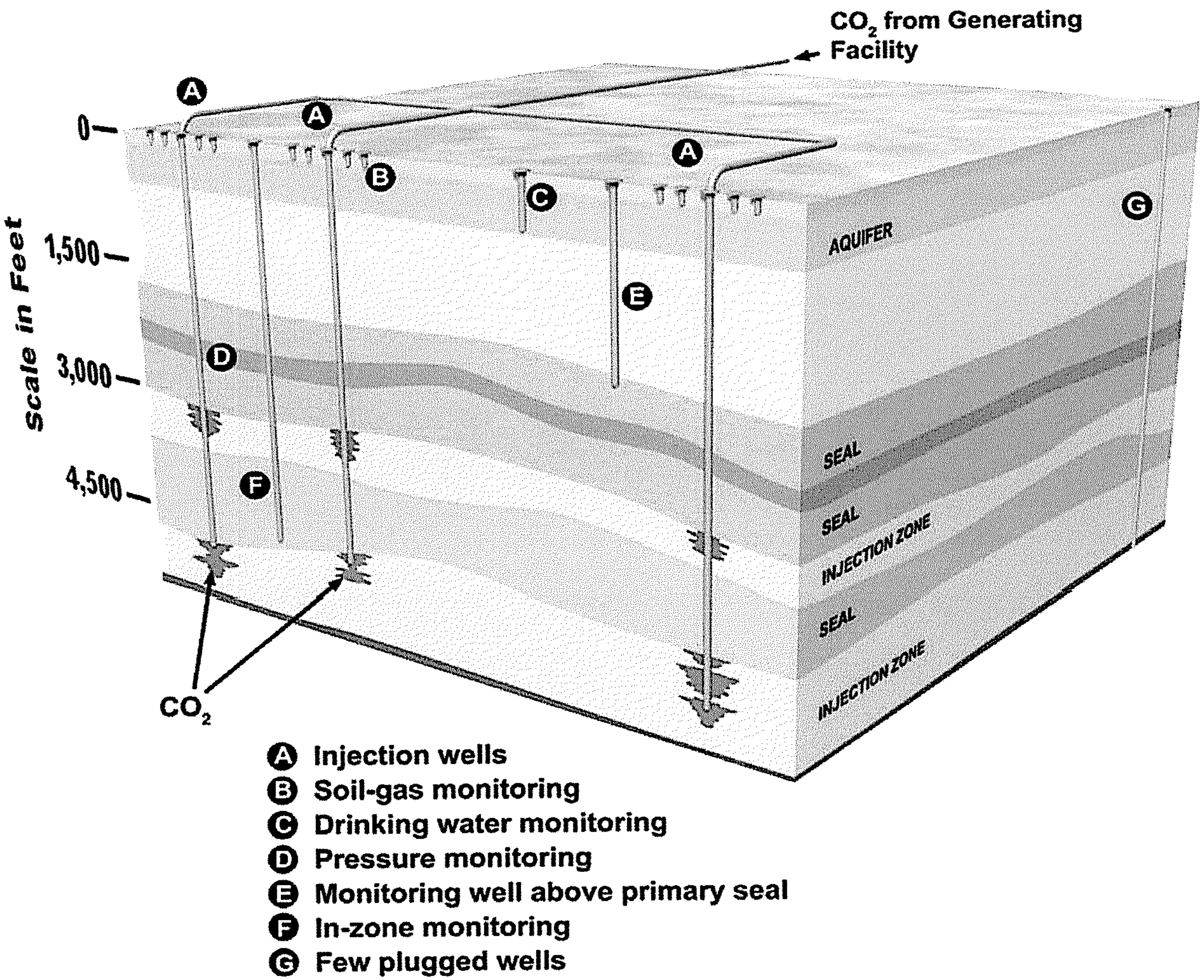
# Carbon capture & sequestration




*What's involved….*

*"Bury" the problem*

*Deep underground wells — depleted oil fields*

*Significant investments in new technology, pumping systems*

*Promising option, but no large-scale commercial application yet*

*"NUMBY"*

*SOURCE: FutureGen Alliance*

# If we can't make it, why not just *move* it?

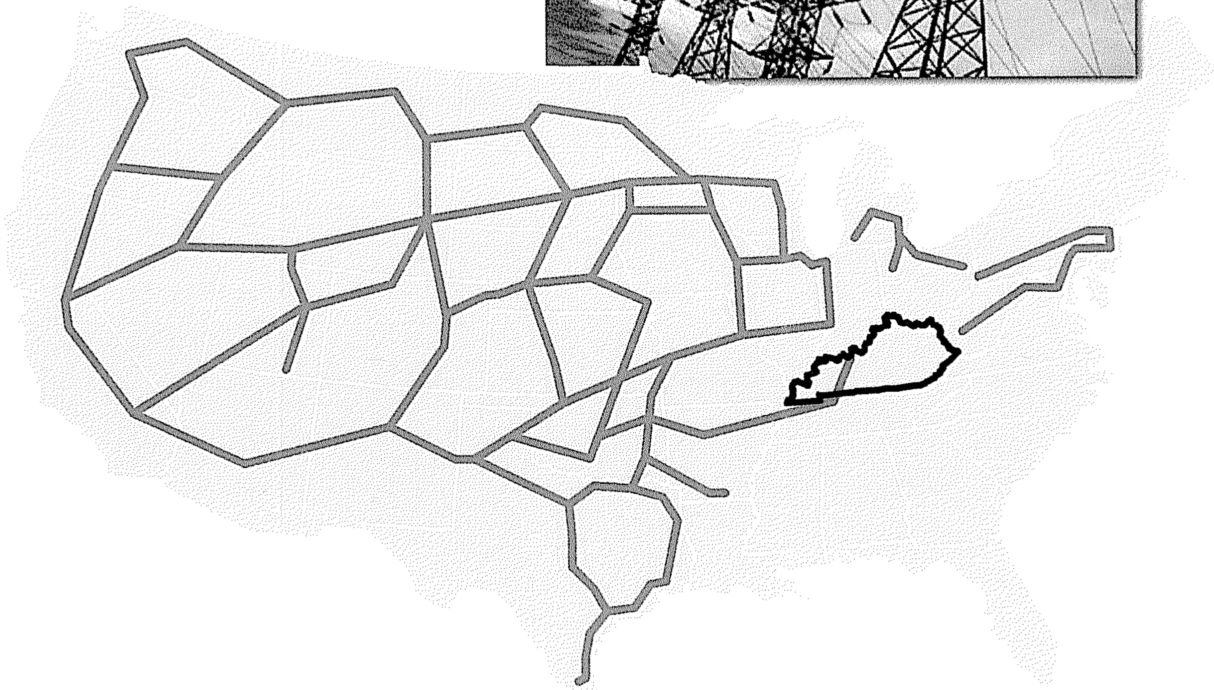
*"Costs" of transmission...*

*Current grid is stretched — would require major new construction at large capital cost*

*Risks of over-reliance on single highway (Canadian blackout)*

*Development/approval time*

*NIMBY*



**Transmission grid system needed to support new renewable power development**

*SOURCE: Dept. of Energy*
*National Renewable Energy Laboratory*

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# Carbon tax ("cap & trade")

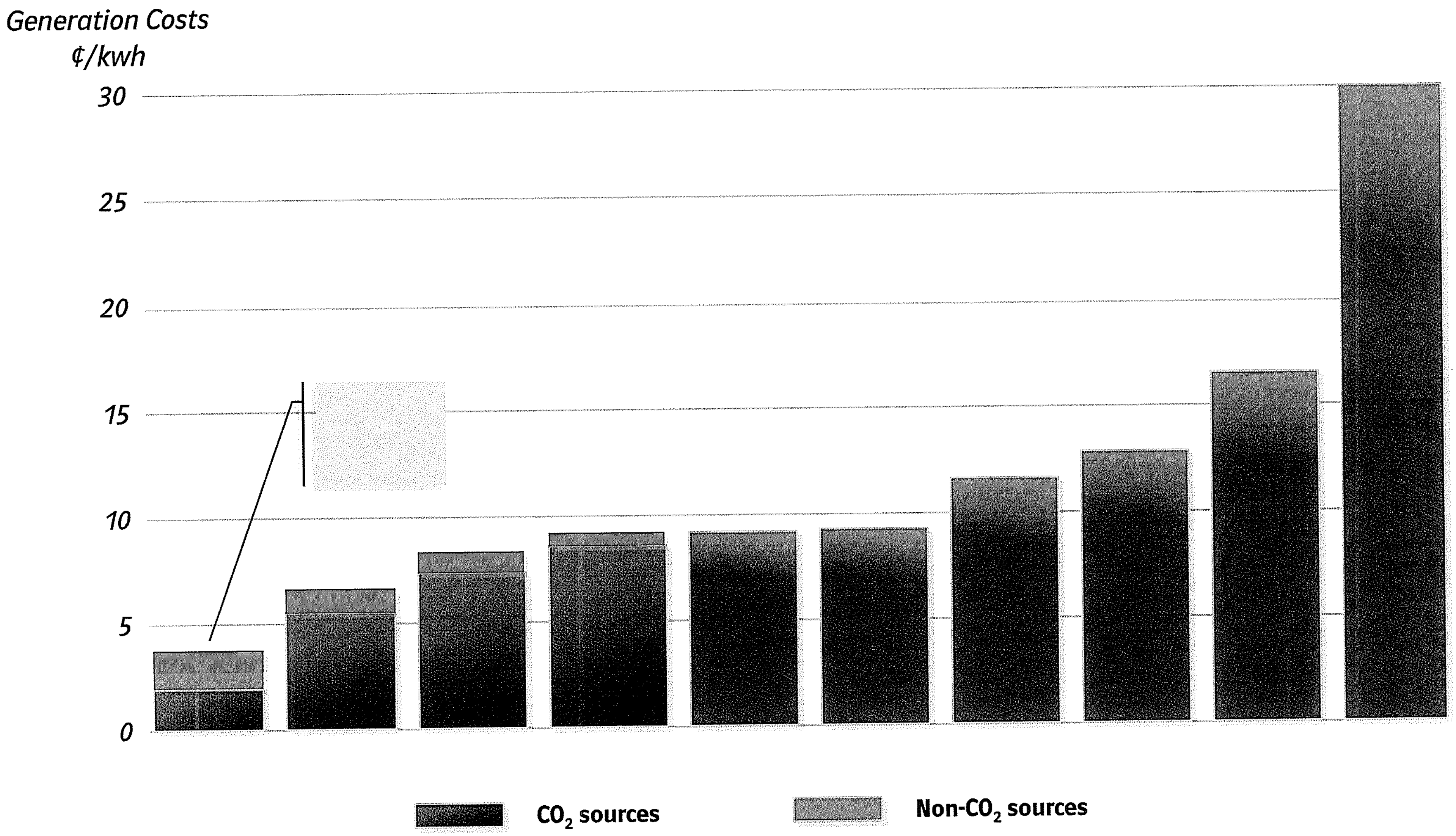
*Federal proposal to "sell" allowances to $CO_2$ producers*

*Concept: All utilities will bid or compete for allowances, market sets price*

*Previously stated goals:*

- *Create new revenue stream for federal budget ($80B/year for 8 years)*
- *Create economic rationale for industry to move more quickly to renewable power*

# Cost Comparison



# American Clean Energy and Security Act of 2009

- *Passed House on June 26, 2009.*
- *Mandates a 17 percent reduction in greenhouse gases by 2020 and 83 percent by 2050 from 2005 levels.*
- *Moves to Senate for vote later this year.*
- *Current form contains elements that are a step in the right direction.*

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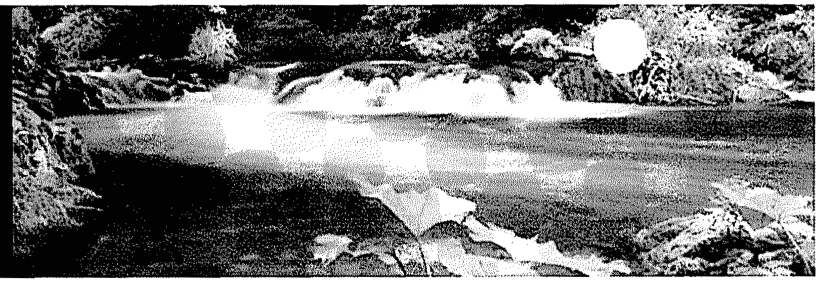
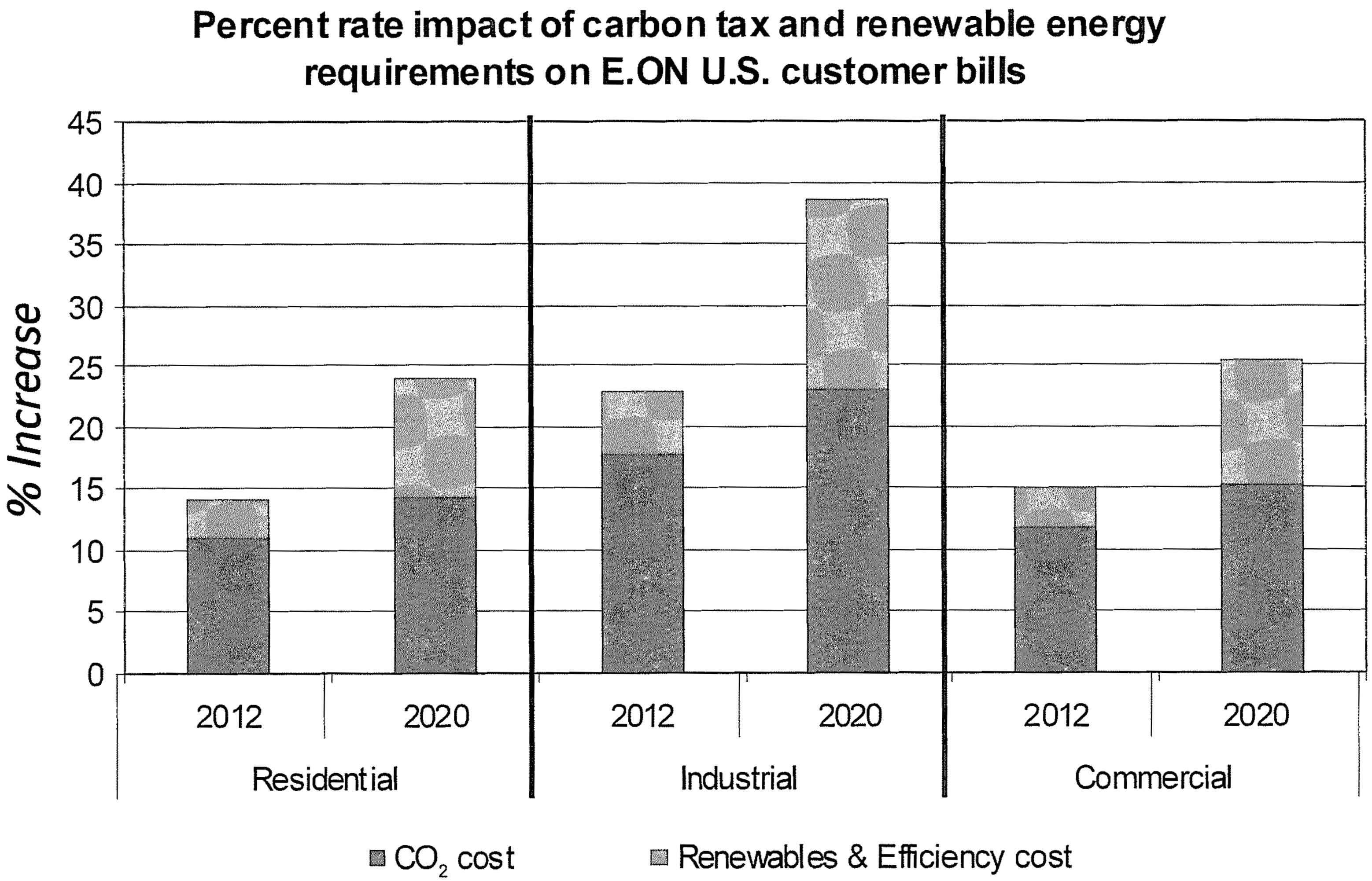
# Estimated costs



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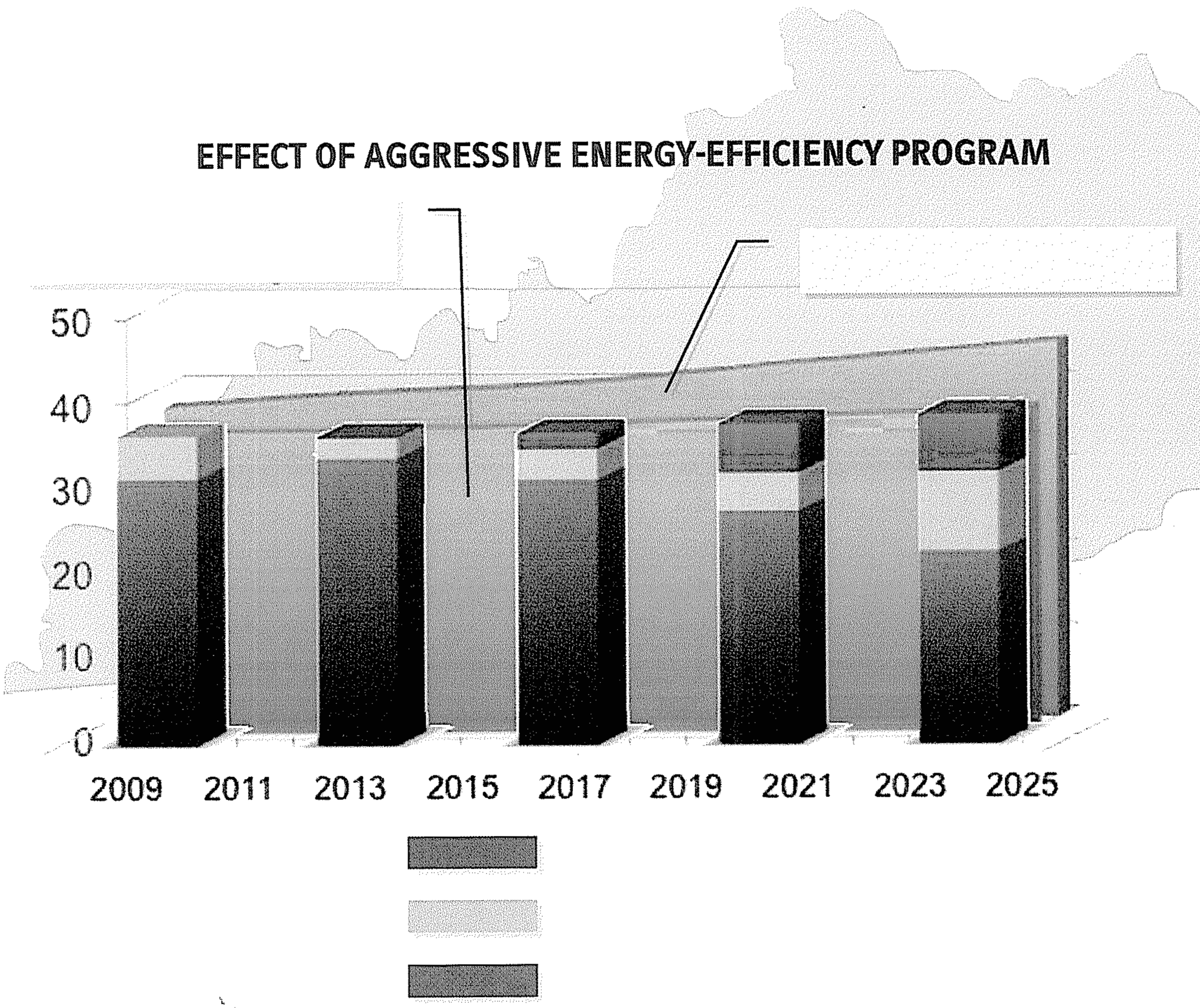
# Reducing demand — the challenge




*What it would take…*

*15+% reduction in demand*

*Unprecedented consumer commitment to energy efficiency*

*Commitment to "smart grid"*

*Less coal in total generation mix, less exposure to carbon tax, but high cost of purchased or developed renewable power sources*

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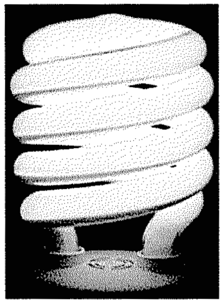
*SOURCE: 2008 Integrated Resource Plan*

# Energy Efficiency Initiatives



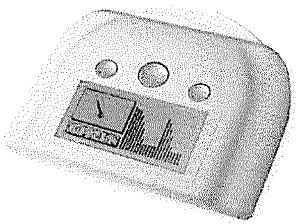
- *E.ON U.S. is investing more than $25 million in energy efficiency programs annually – at least $182 million over the life of the program*

  *Examples:*

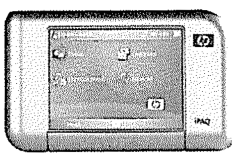
  -- *Enhanced energy audits*

  -- *Commercial rebates*

  -- *Residential lighting*



- *Expected to reduce the need for additional generation by more than 500 megawatts*



- *Conserve Energy During Heavy Demand*

  -- *Load control program – partnership with customers that allows us to cycle off AC units during peak demand*

  -- *Smart meter pilot program –helps customers manage their usage*

# What are "the next steps?"

- *Understand that rising energy costs will be a way of life for years to come – consider everything you do with that in mind*
- *Make major, sustained commitment to energy efficiency*
- *E.ON U.S. – to address issues of carbon capture and sequestration with help of policy-makers*
- *E.ON U.S. – share information and work constructively with policy-makers*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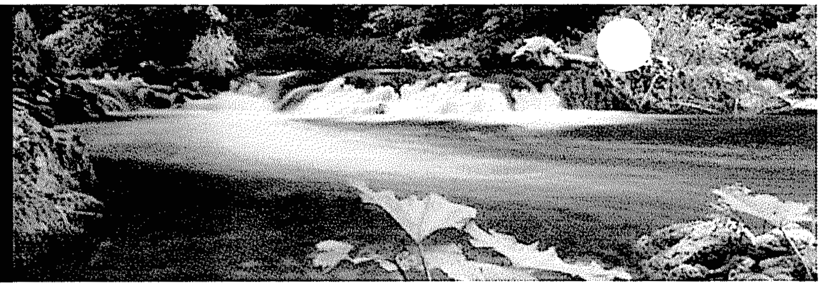
# Balanced Outcome



- *Insist on a thorough evaluation of cost*
- *Allow technology to catch up*
- *Demand an equitable allocation of carbon credits*
- *Be efficient – seek incentives for efficiencies*


*"To build may have to be the slow and laborious task of years.*

*To destroy can be the thoughtless act of a single day."*

**— Winston Churchill**

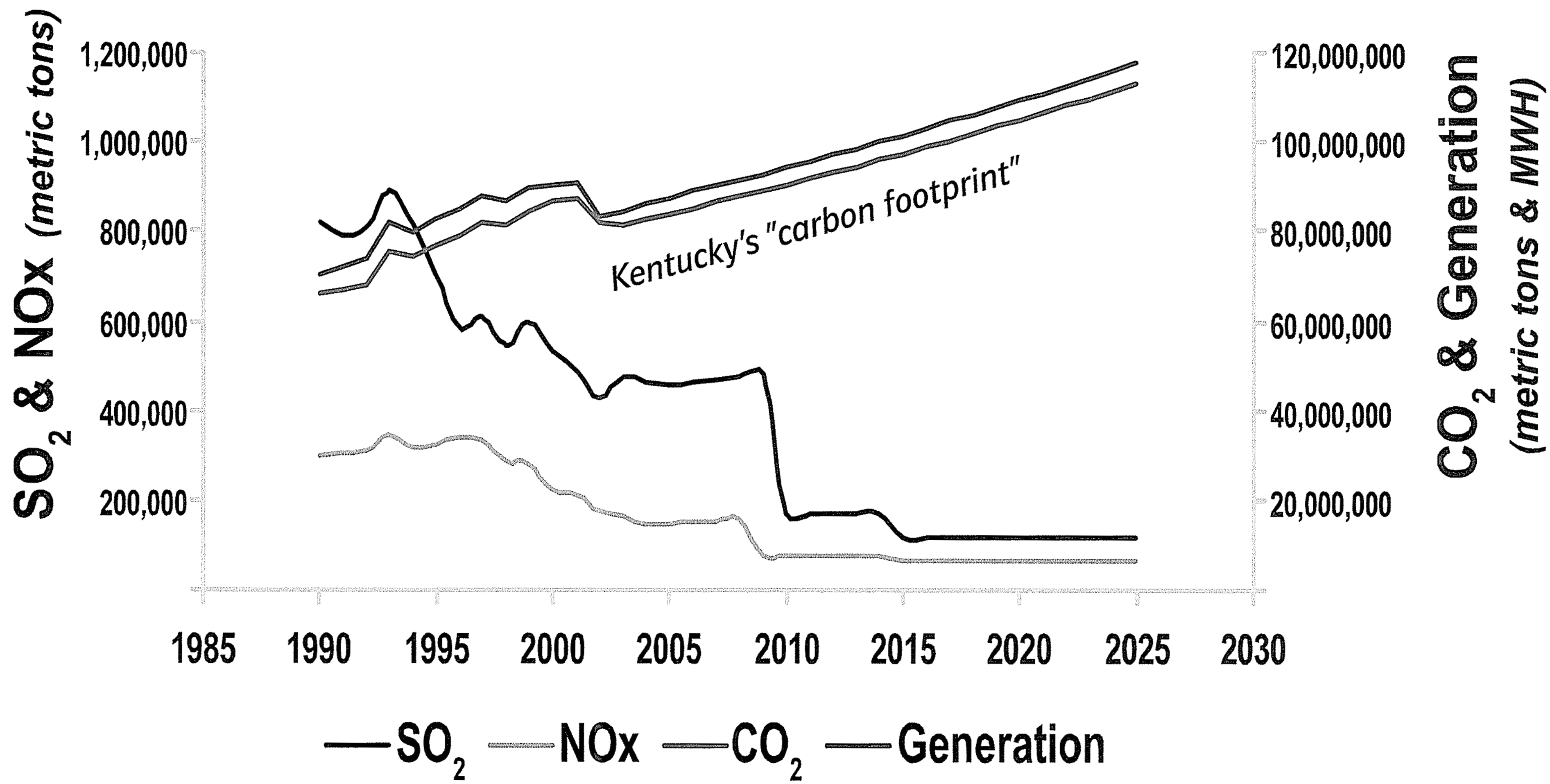
LG&E KU

April 28, 2009

# Kentucky's carbon footprint: Where does it lead?

# Kentucky coal-fired generation

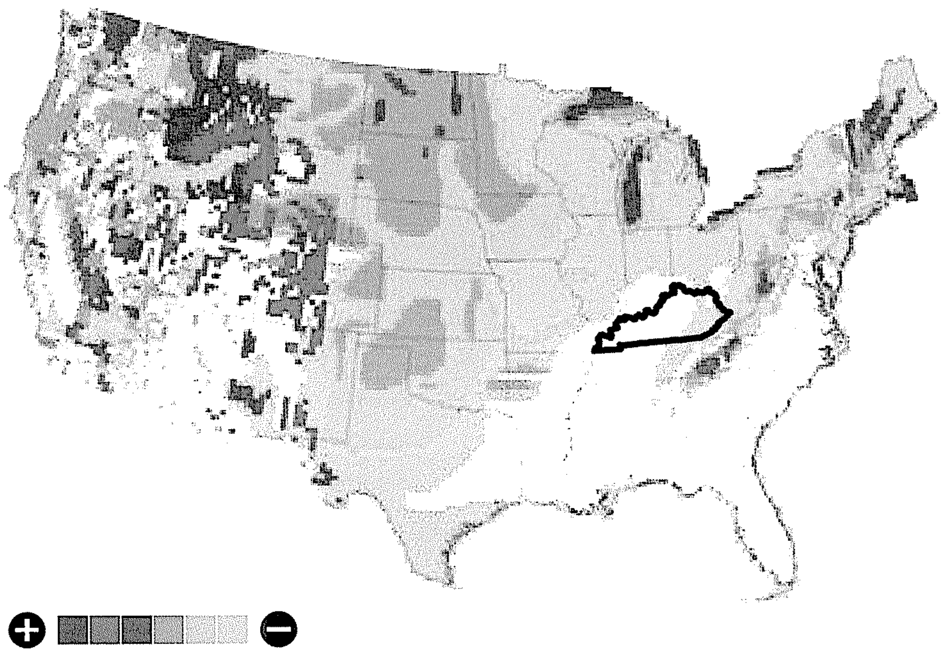
## $CO_2$ emissions: **100 times** larger issue than $SO_2$/NOx



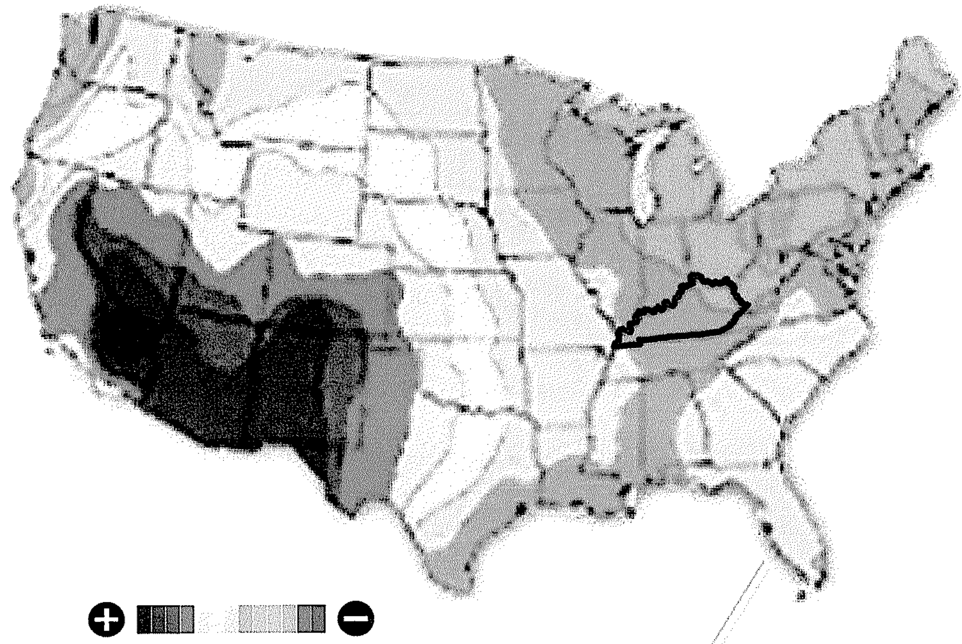

*Sources: U.S. DOE Energy Information Administration for historic emissions and generation. U.S. EPA for future $SO_2$ and NOx state budgets. In-house projections of generation and $CO_2$ based on 1.5% annual growth.*

# Considerations — wind and solar

## *Wind*



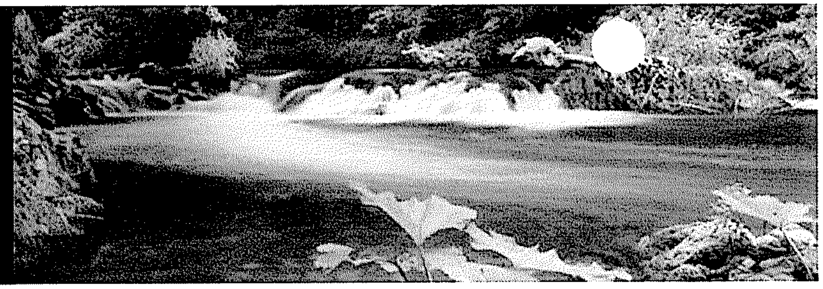

## *Solar*

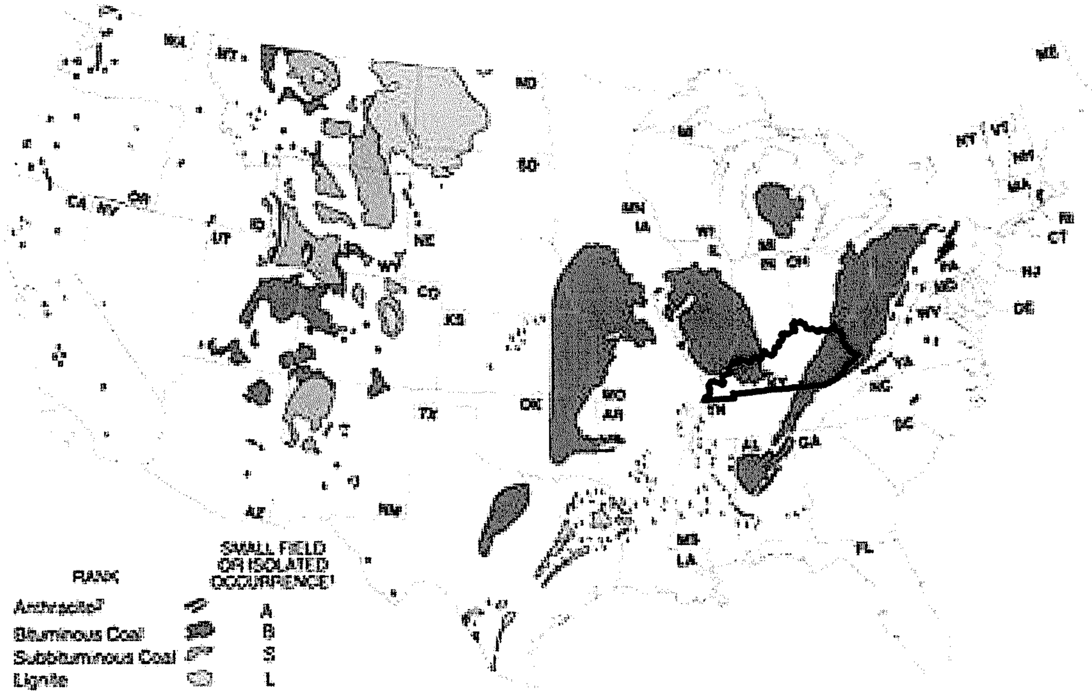



*Why not Florida?*
*Frequent afternoon thunderstorms*

*SOURCES: Dept. of Energy*
*National Renewable Energy Laboratory*

# Considerations — coal






SOURCE: Dept. of Energy

*One of the most efficient fuels for electrical generation — 90% availability*

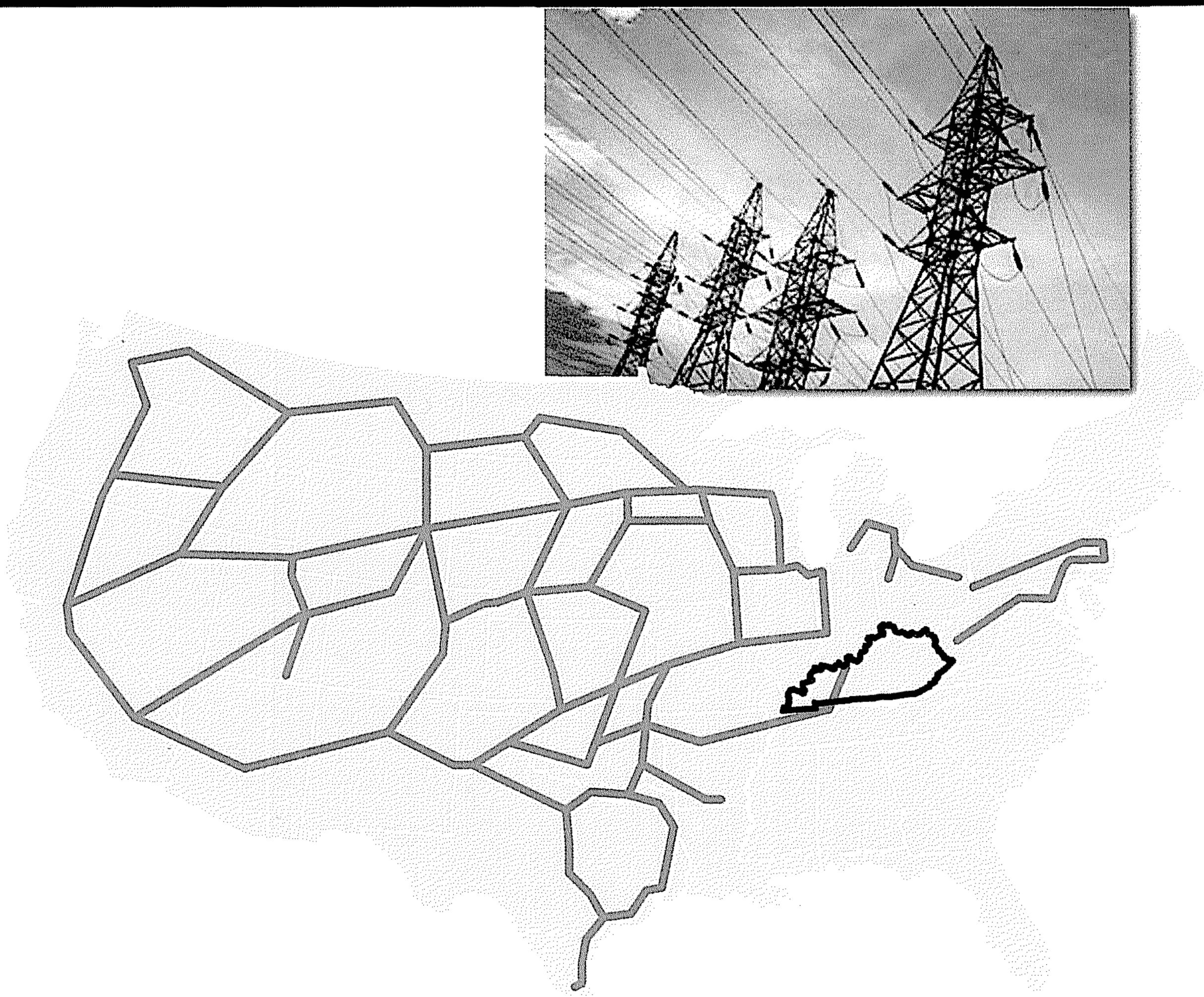
*50% of U.S. power produced today*

*95% of Ky. power produced today*

*One of the largest fixed-source producers of $CO_2$*

*Relatively low transportation costs (river barge)*

# If we can't make it, why not just *move* it?



*"Costs" of transmission…*

*$10-18/MWh — 10-20% increase alone*

*Current grid is stretched — would require major new construction at large capital cost*

*Risks of over-reliance on single highway (Canadian blackout)*

*Development/approval time*

*NIMBY*

**Transmission grid system needed to support new renewable power development**

*SOURCE: Dept. of Energy*
*National Renewable Energy Laboratory*

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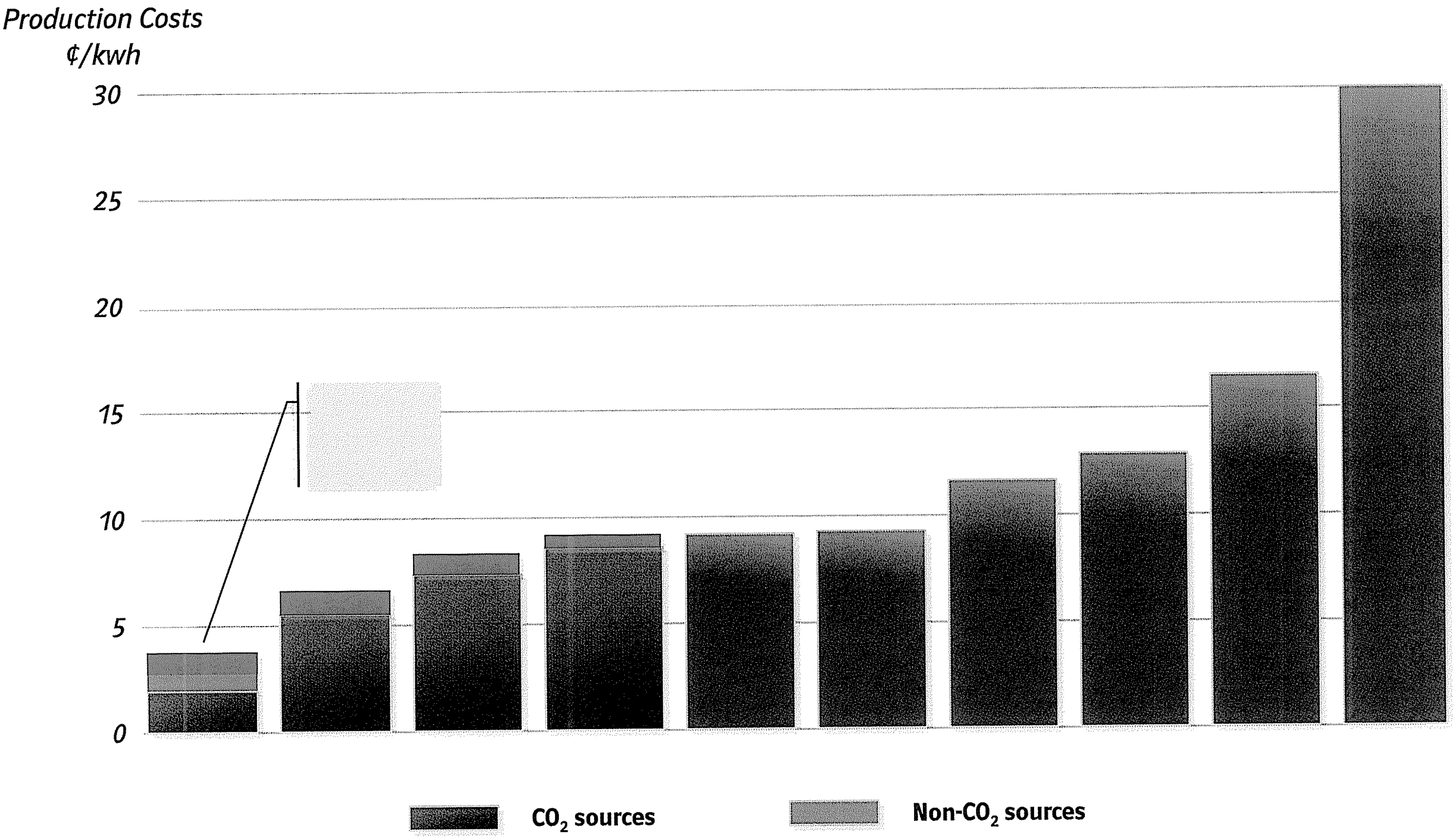
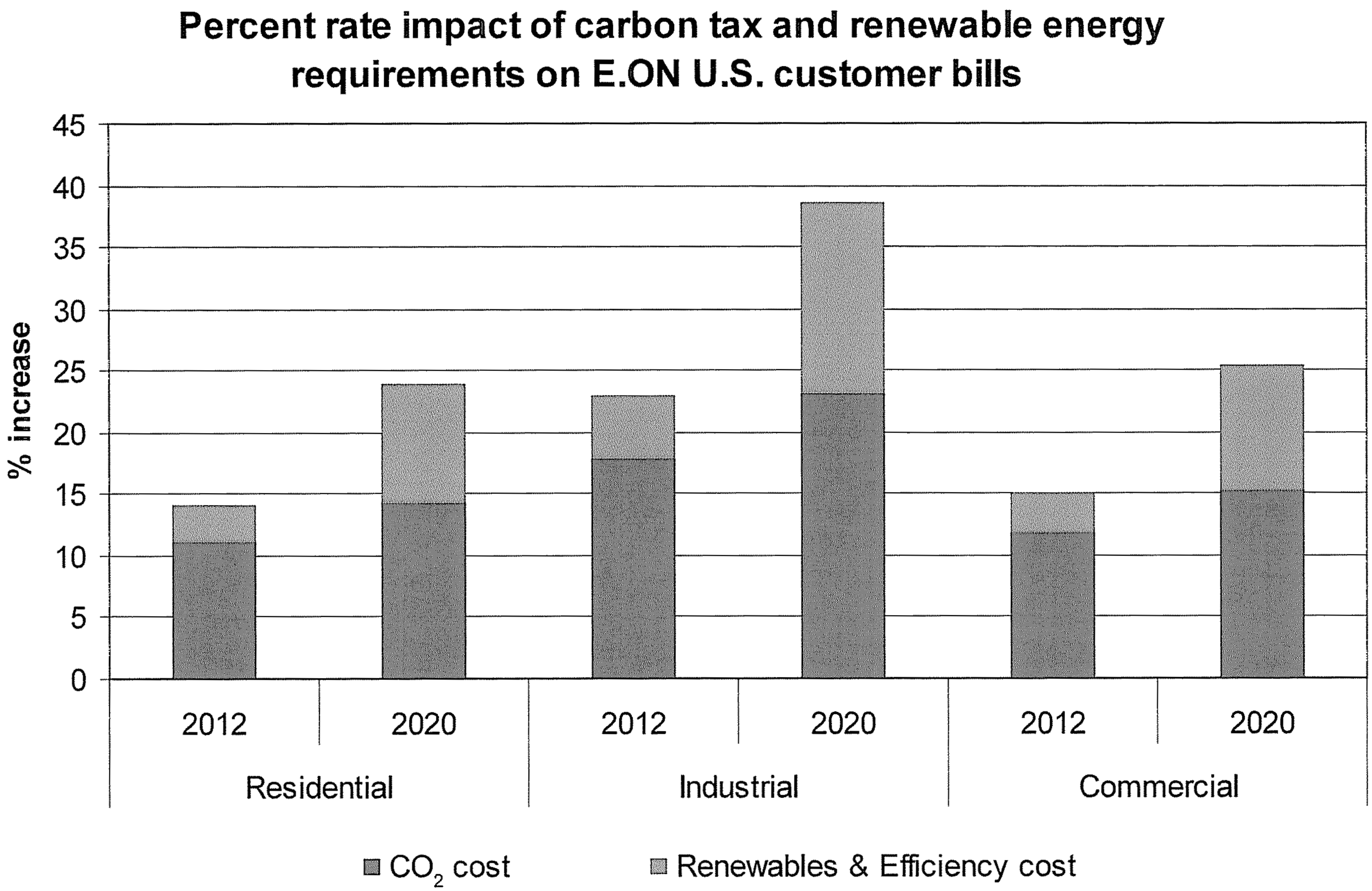
# Cap & trade — incentive or tax?



# Estimated costs




- *Percentage increases calculated using 2008 rates applied to 2020 projected sales*
- *CO2 allowance is calculated at $20 a ton, allocation methodology is 41% purchase in 2012, 53% purchase in 2020*
- *Assumes utilities meet the CERES target entirely through purchase of Alternative Compliance Payments (ACPs) set in the bill at 2.5¢ per KWH in 2010 (and subsequently indexed)*

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# Balanced Outcome

- *Insist on an honest evaluation of cost*
- *Allow technology to catch up*
- *Demand a fair allocation of carbon credits*
- *Be efficient – seek incentives for efficiencies*


*"To build may have to be the slow and laborious task of years. To destroy can be the thoughtless act of a single day."*

**— Winston Churchill**

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# Environmental Expansion Plan to Meet a 15% RPS and a 23 Million Ton $CO_2$ Cap

February 20, 2009

e·on | U.S.

# Background: possible Federal RPS

*In Sept 2008, House Democrats released a 290-page energy bill that contains a section titled "Federal Renewable Electricity Standard" with these targets....*

| Calendar years | Required Annual % |
|---|---|
| 2010 | 2.75% |
| 2011 | 2.75% |
| 2012 | 3.75% |
| 2013 | 4.50% |
| 2014 | 5.50% |
| 2015 | 6.50% |
| 2016 | 7.50% |
| 2017 | 8.25% |
| 2018 | 10.25% |
| 2019 | 12.25% |
| 2020 and thereafter | 15% |

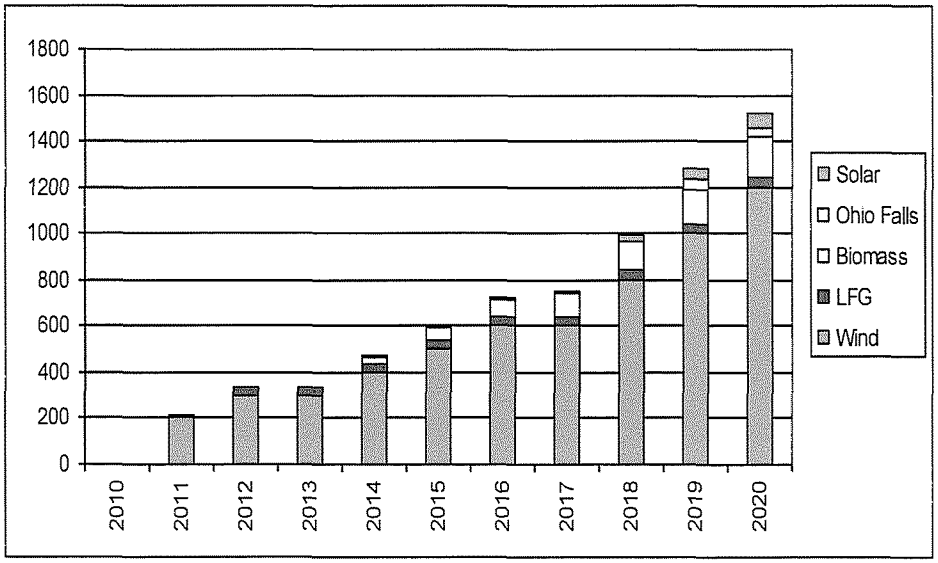
# Environmental Expansion Plan goals and assumptions

- *First meet annual RPS requirements - gradually increasing to 15% in 2020*
  - *Energy sales are based on 2008 BAU case with lower sales forecast*
  - *Purchase and sale of Renewable Energy Certificates (REC) is allowed*
  - *Regulatory and environmental approvals will be timely*
  - *Expansion plan is not optimized*

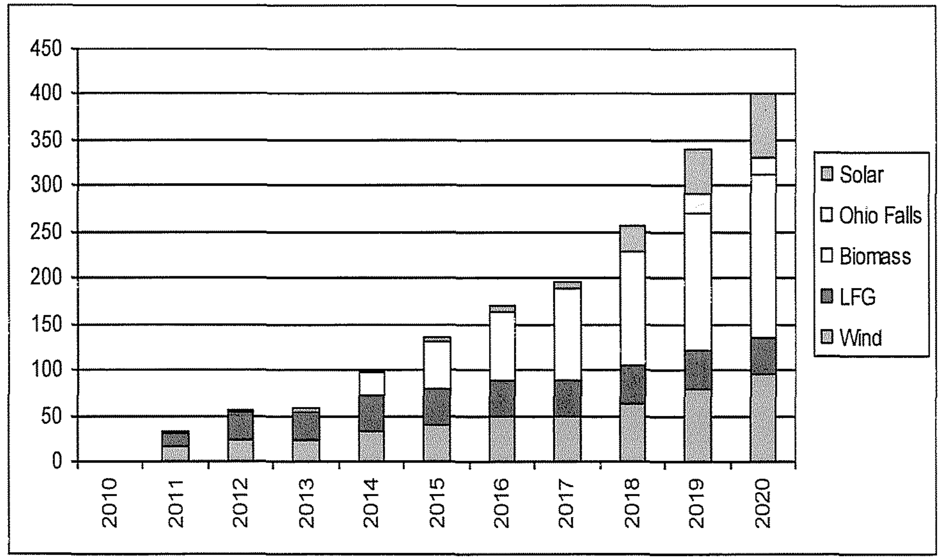
- *Then meet a $CO_2$ emission cap of 23 million tons by 2020*
  - *Nuclear generation will not be available to E.ON by 2020*
  - *CCS will not be in large scale commercial operation by 2020*
  - *Replacement of 1500 MW of coal generation with NGCC is back loaded*
    - *Intermediate $CO_2$ targets could accelerate coal retirements*
    - *Allowance purchase may be possible to delay retirements*
    - *The cost of allowances will base load NGCC generation*
  - *Assumes transmission and natural gas will be available*

# Renewable capacity additions to meet 15% RPS target

**MW (installed) - cumulative**




**MW (firm) - cumulative**




| **Unit Capacity** | Wind | LFG | Biomass | PV Solar | Conc. Solar | Ohio Falls |
|---|---|---|---|---|---|---|
| Installed MW | 100 | 10 | 25 | 1 | 20 | 40 |
| Firm MW | 8 | 10 | 25 | 1 | 15 | 20 |
| Capacity Factor % | 28% | 90% | 90% | 14% | 14% | 49% |

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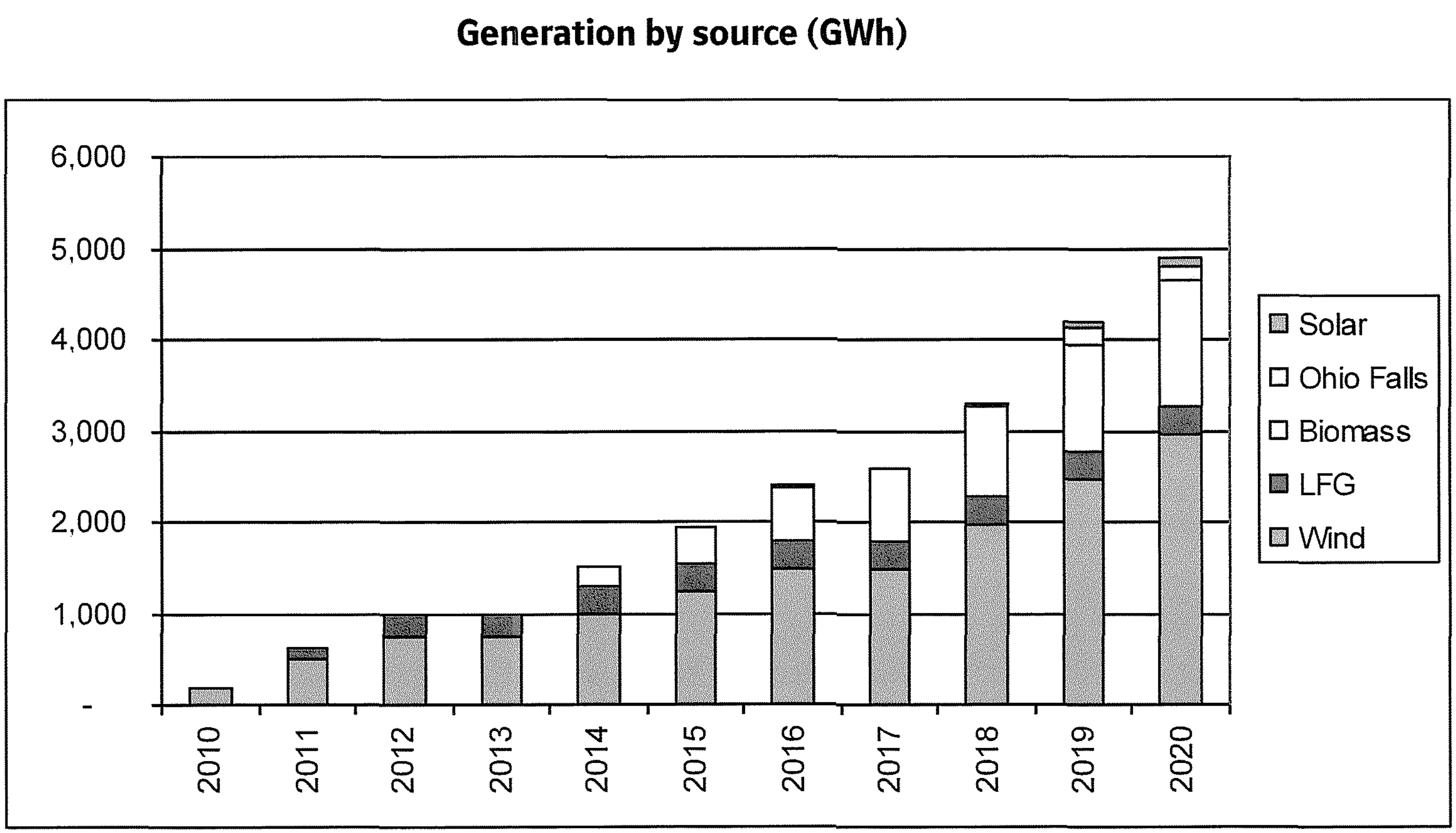
# Incremental energy from renewable resources



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# Actions to meet a 15% RPS*

- Add 1100 MW of wind generation power purchase agreements
  - Average addition of over 100 MW per year from 2010 to 2020
  - Transmission across MISO and/or PJM required
  - Upgrades to MISO, PJM and E.ON transmission system likely
- Add 100+MW of self-build wind in Kentucky in mid decade
  - E.ON C&R identified a potential project in Bell County
- Add 40 MW of landfill gas generation
  - 20 MW identified with Republic
  - Currently E.ON's "least-cost green generation option"

* Note that many - particularly Federal - RPS proposals accept "energy efficiency savings" as a compliance mechanism, and therefore it may not be necessary to meet the target through supply-side investments alone.

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# Actions to meet a 15% RPS (continued)

- Add 175 MW of biomass capacity at surviving coal plants
  - Seven 25 MW units between 2014 and 2020
  - Will require the creation of a biomass fuels industry
- Add 40 MW of capacity to Ohio Falls
  - FERC license modification required
  - Significant archeological issues to be resolved
- Add 1 MW of PV solar per year between 2011 and 2020
  - Highest unsubsidized cost of green generation
- Add 20 MW (60 MW total) of concentrating solar to each new NGCC plant
  - Only large scale applications exist in desert regions

# Additional actions required to meet 23 million TPY $CO_2$ cap

- $CO_2$ emissions still exceed cap even after adding renewables capacity to meet 15% RPS standard
  - $CO_2$ emissions total ~36 M tons in 2010
  - Renewables reduce $CO_2$ to ~32 M tons by 2020, still 9 M tons over cap
- Replacing 500 MW of coal generation with NGCC saves ~2.6 M TPY
  - First NGCC in 2018 replaces:
    - Green River 3 & 4, Tyrone 3, Brown 1, and Cane Run 4
  - Second NGCC in 2019 replaces:
    - Cane Run 5 & 6, and Brown 2
  - Third NGCC in 2020 replaces Brown 3
- New NGCC will likely be located near retired coal units to utilize existing transmission; assumes natural gas supply available

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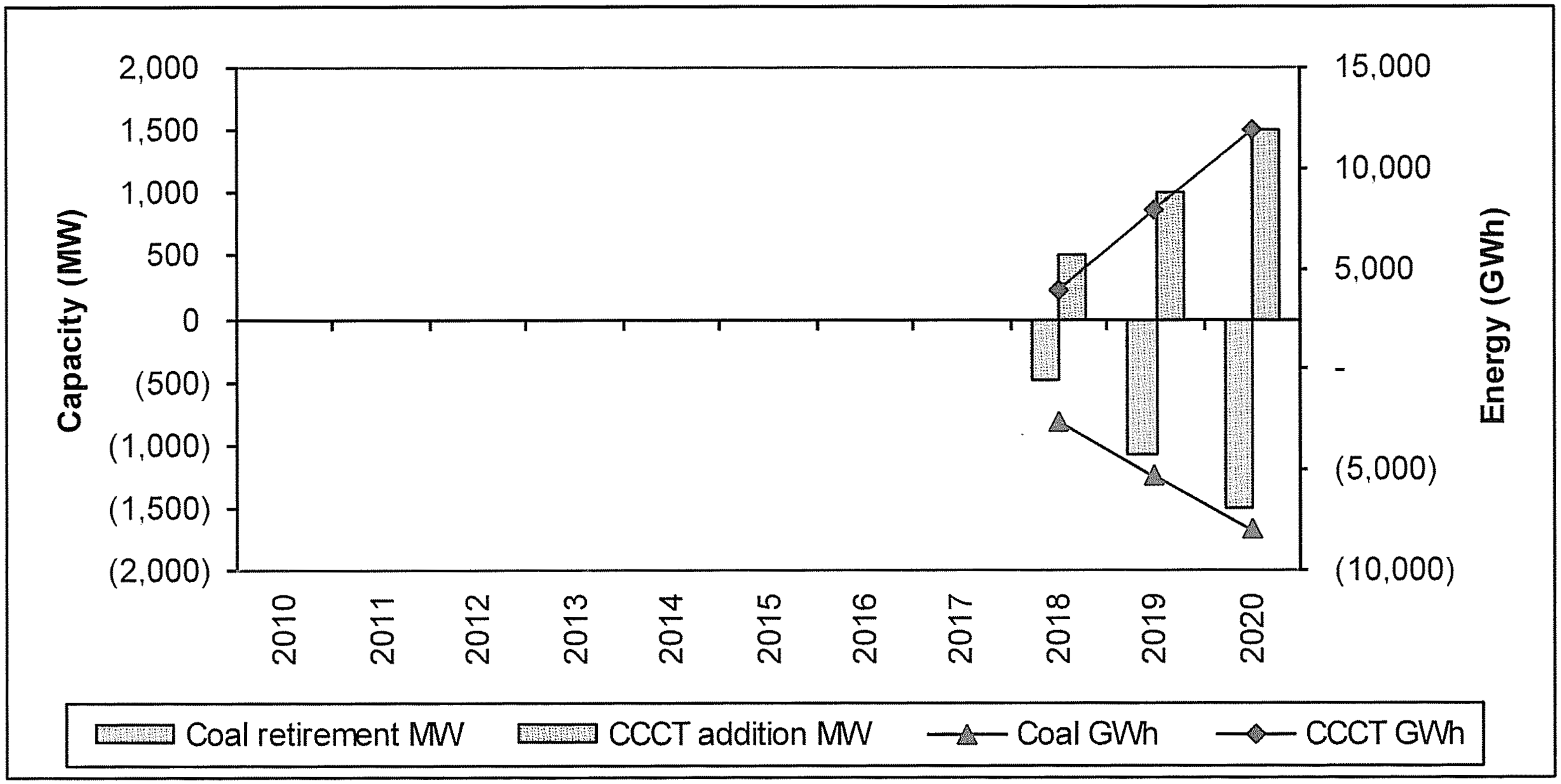
# *Capacity retirements/additions to meet 23M ton CO2 cap*

*(in addition to renewable resource additions)*



# Estimated capital cost of the Environmental Expansion Plan

- Capital investments of ~$5.4 billion between 2010 & 2020
  - $2.4 billion in renewables capacity ($0.9 solar, $0.9 biomass, $0.3 wind, $0.3 hydro)
  - $2.9 billion in CCCT
  - Peak investment of over $1.3 billion in 2017

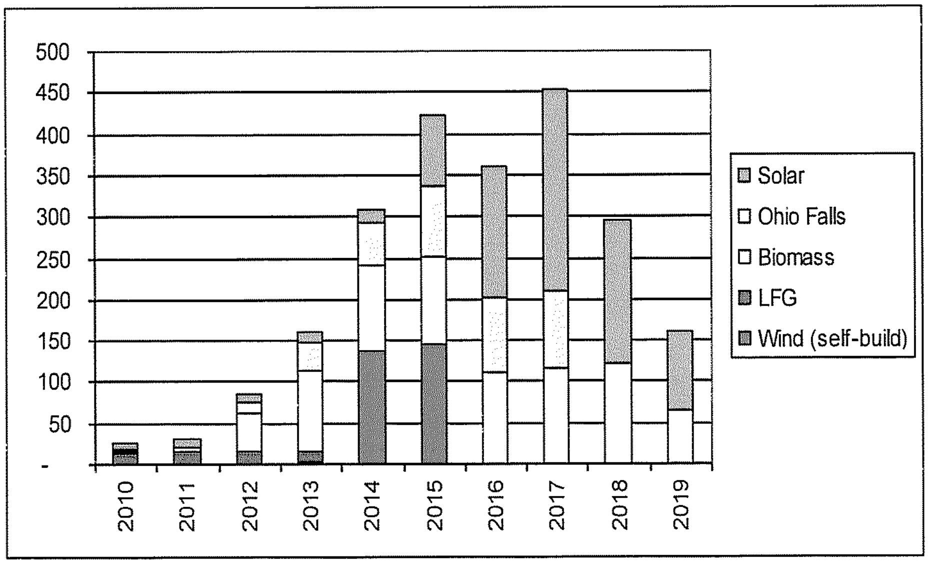
- Capital investment is for generation only ( excludes transmission improvements)

- Multiple small projects will require significant headcount additions to develop, permit, engineer, construct and operate

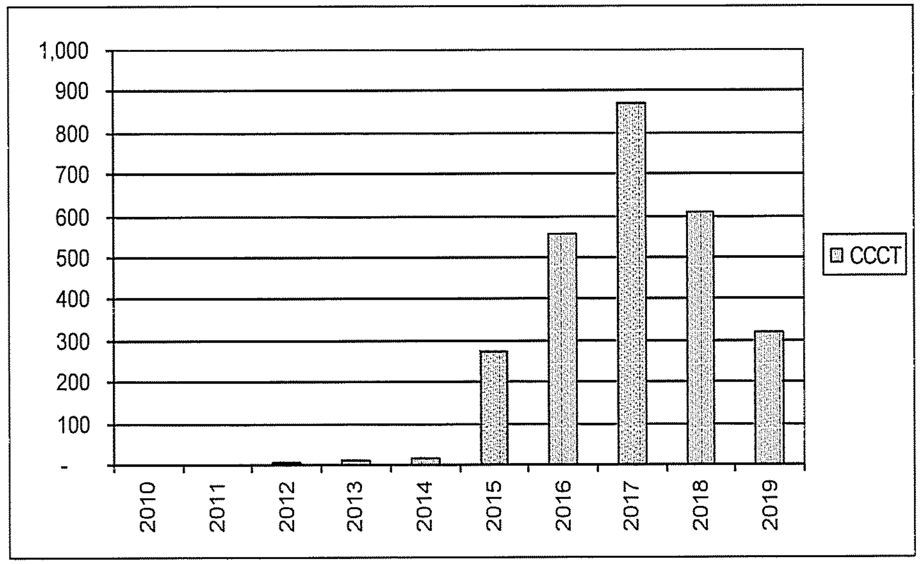
# Annual capital investment (Environmental Expansion Plan)

*($ million)*

**Renewables**




**CCCT**

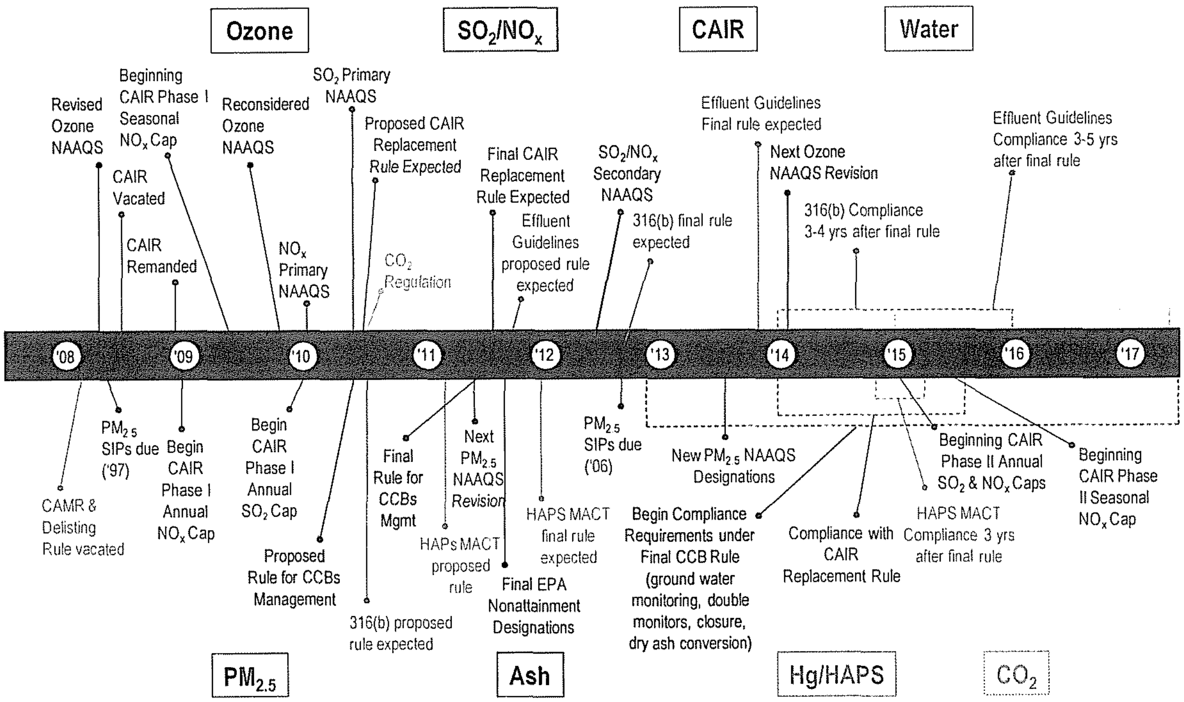


# Rate impact of Environmental Expansion Plan

- *If E.ON U.S. is mandated to comply with a 15% RPS target and to reduce $CO_2$ emissions to a 23M ton cap by 2020, the cost – measured in terms of the lifetime incremental capital and operating costs associated with meeting these targets – will total just under $8 billion in PV terms*
- *However, it can be assumed that in the absence of such mandatory compliance the Utilities would be operating under a $CO_2$ "cap-and-trade" regime. Assuming $CO_2$ emissions pricing in line with the 2008 LTP (reference case) projection – rising from ~$15/ton in 2013 to over $80/ton by 2030 – the value of the $CO_2$ emissions reduction over the lifetime of the new renewable and CCCT assets is ~$6.1 billion in PV terms*

# 1. Executive Summary

The Environmental Protection Agency (EPA) is considering significant new environmental regulations in the coming years. The timing and content of these regulations could have a significant impact on the way E.ON U.S. operates its generation fleet and transmission assets. The graph below shows the possible timeline for environmental regulatory requirements for the utility industry:




*adapted from Wegman (EPA 2003) Updated 2-15-10

To evaluate the potential impacts of these regulations, a scenario team developed and analyzed the following three scenarios:

1. EPA Regulations
2. RPS Compromise
3. $CO_2$ Intensity Cap

All three scenarios considered the impact of Ozone, $SO_2/NO_x$, CAIR, $PM_{2.5}$, and Hg/HAPS regulations, by requiring updated environmental controls on all coal units by 2016. These controls potentially include selective catalytic reduction (SCR), selective non-catalytic reduction (SNCR), flue gas desulfurization (FGD), mercury (Hg) removal systems, $SO_3$ mitigation, fabric filters, and/or electrostatic precipitators. To address the potential $CO_2$ regulations, the EPA Regulations scenario included a requirement for increased turbine efficiency by 2016, which was met with dense pack turbine upgrades on all large coal units. The RPS Compromise scenario does not include explicit $CO_2$ regulation, but requires a Renewable Portfolio Standard (RPS) consistent with the Waxman-Markey bill beginning in 2012. The $CO_2$ Intensity Cap scenario limits the metric tonnes of $CO_2$ per MWh generated in 2020 and beyond, consistent with the $CO_2$ caps proposed by Waxman-Markey.

The table below summarizes the impacts in each scenario to the E.ON U.S. generation fleet. In all scenarios, (a) the Tyrone and Cane Run units are retired in 2016 and replaced by a combined cycle unit (at the Cane Run site) and (b) the Green River units are retired in 2020. Clearly, the $CO_2$ Intensity Cap scenario has the largest impact to the existing fleet.

| **EPA Regulations** | **RPS Compromise** | **$CO_2$ Intensity Cap** |
|---|---|---|
| 2016: Retire CR/TY3 (634 MW)<br>2016: New CCCT (640 MW)<br>2020: Retire GR3&4 (163 MW)<br>2020: New SCCT (190 MW) | 2016: Retire CR/TY3 (634 MW)<br>2016: New CCCT (640 MW)<br>2020: Retire GR3&4 (163 MW)<br>By 2020: New Wind (1,270 MW) and Biomass (190 MW) | 2016: Retire CR/TY3 (634 MW)<br>2016: New CCCT (640 MW)<br>2020: Retire GR3&4 (163 MW)<br>2020: Retire BR, MC, GH2 (2,653 MW)<br>2020: 4 New CCCT (2,560 MW) |

The table below shows the net present value of revenue requirements as well as capital expenditures over the LTP period (2010-2019) for each of the three scenarios:

| | **NPVRR ($B)** | **Capital ($B)** |
|---|---|---|
| EPA Regulations | 24.2 | 7.3 |
| RPS Compromise | 26.2 | 10.8 |
| CO2 Intensity Cap | 30.0 | 10.3 |

The $CO_2$ Intensity Cap scenario has the highest net present value of revenue requirements; however, the RPS Compromise scenario has the highest capital expenditures.

## 2. Scenario Assumptions

The scenario team considered the impact over the next 10 years of potential EPA regulations on generation and transmission capital plans, operating costs, and fuel costs. The table below provides an overview of the key assumptions for each scenario. With inputs from a variety of sources regarding capital and operating costs, the scenario team developed an optimal expansion plan for each scenario. The evaluation of each scenario is discussed in more detail in the following sections.

| Inputs | Existing LTP | EPA Regulations | RPS Compromise | CO2 Intensity Cap |
|---|---|---|---|---|
| Hg/HAPS – all units <25MW | | ✓ | ✓ | ✓ |
| $SO_2/NO_x$ – $SO_2$ 100 ppm hourly | | ✓ | ✓ | ✓ |
| CAIR – 0.25 lb $SO_2$; 0.11 lb $NO_x$ | ✓ | ✓ | ✓ | ✓ |
| Ozone – 60-70 ppm | | ✓ | ✓ | ✓ |
| Water – 316(b) | | ✓ | ✓ | ✓ |
| $PM_{2.5}$ | | ✓ | ✓ | ✓ |
| Ash – wet storage limited | | ✓ | ✓ | ✓ |
| $CO_2$ – BACT (efficiency and co-fire) | | ✓ | | |
| $CO_2$ | Cap & Trade 2012 | | | Intensity Cap 2015 |
| Renewables | Alt Comp Pmts | | 2012 - No ACP | ✓ |
| Renewables Trans. Build | | | ✓ | ✓ |
| Load Forecast | LTP (1.4% CAGR 2013-20) | LTP | ↓ (W-M Efficiency) | ↓ (W-M Efficiency) |
| Gas Price (Coal @ LTP price) | LTP | LTP | ↓ | ↑ Initially, then LTP |
| Wholesale Electricity Price | LTP | ↑ | ↓ | ↑ Initially, then LTP |

# 3. EPA Regulations Scenario

## 3.1. Overview

The EPA Regulations scenario evaluates the impact of stricter air quality, water, and combustion by-product standards. Given the uncertainty that exists regarding whether these standards can be implemented on the EPA's proposed timeline, the implementation of these standards is assumed to be delayed by one year to January 2016. The primary implication of these standards is that existing coal units without new FGD and SCR equipment will either have to be retrofitted with this equipment or retired. In this scenario, the Tyrone and Cane Run units are retired in 2016 and replaced by a combined cycle unit (at the Cane Run site). The Green River units are retired in 2020 and replaced by a simple cycle combustion turbine. More details regarding this scenario are included in the following sections.

## 3.2. Assumptions

### 3.2.1. Retirements

Tyrone 3 and Cane Run 4-6 were assumed to be retired in 2016 and Green River 3-4 were retired in 2020. The scenario team assumed the company would be able to reach an agreement with the EPA to allow Green River 3-4 to operate through 2019. If this doesn't happen, Green River 3-4 would also have to be retired in 2016. The retirement cost was assumed to be $2 Million (2010 $) per unit. The chart below shows potential Fixed O&M (FOM) savings for retired units:

| 2012 $M/yr | FOM |
|---|---|
| Brown 1 | 4 |
| Brown 2 | 6 |
| Cane Run 4 | 10 |
| Cane Run 5 | 10 |
| Cane Run 6 | 15 |
| Green River 3 | 6 |
| Green River 4 | 8 |
| Tyrone 3 | 7 |

### 3.2.2. Capital Savings

The chart below shows the capital savings for the EPA Regulations scenario. These savings are driven by unit retirements and include costs related to scheduled maintenance, major replacements (precipitators, stator and generator rewind), and landfills.

| Capital Savings ($M) | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 |
|---|---|---|---|---|---|---|---|---|---|---|
| Tyrone 3 | 0 | 0 | 0 | 0 | 0 | 0 | (2) | (2) | (2) | (2) |
| Cane Run 4-6 | 0 | 0 | 0 | 0 | (0) | (6) | (28) | (20) | (24) | (25) |

### 3.2.3. New SCRs/SNCRs

In order to comply with stricter air quality standards, SCRs would need to be installed on Ghent 2 and Mill Creek 1-2 by 2016 at an average cost of $400/kW and all SCRs would be required to operate year-round. Also, if SCRs are installed at Mill Creek 1-2, the electrostatic precipitators would need to be replaced at a cost of approximately $25M per unit. This cost was not included in the analysis.

Installing SCRs on Brown 1-2 would be very costly ($670/kW), so SNCRs were evaluated as an option. Compared to an SCR, capital for an SNCR is less ($82/kW) because there is no catalyst; however, variable O&M is higher because more reagents are required in the process. Also, an SNCR has a removal rate of approximately 50%, compared to around 90% for an SCR. Because of the lower $NO_x$ emission rate, some uncertainty exists regarding whether SNCRs will meet $NO_x$ emission limits at Brown 1-2.

### 3.2.4. FGD Upgrades

In the EPA Regulations scenario, the FGDs at Mill Creek are updated to meet the more stringent air quality standards in 2016 at an average cost of $100/kW. If Cane Run was not retired, its FGDs would have to be replaced in 2016 at an average cost of $260/kW.

### 3.2.5. Mercury Removal

For the units not retired in 2016 or 2020, Hg removal systems would need to be installed in 2016. This cost includes new systems for adding Hg-controlling reagents as well as new precipitators at Ghent 1, 3-4, Mill Creek 1-4, and Cane Run 4-6.

### 3.2.6. $CO_2$ Efficiency

Dense pack turbine upgrades were assumed to be the Best Available Control Technology (BACT) for $CO_2$ emissions. The following units received dense pack turbine upgrades in 2016: Brown 3, Ghent 1-4, Trimble County 1, and Mill Creek 4. A 3% increase in maximum capacity was applied to units with the dense pack turbine upgrades to capture the impact of increased efficiency. The other smaller units not retired in 2016 or 2020 were assumed to be retrofitted to co-fire biomass (prorated capital based on $14 million for 500 MW retrofit).

### 3.2.7. Expansion Plan Options

The table below shows unit characteristics for the three expansion plan options considered – 3x1 Combined Cycle Combustion Turbine (3x1 CCCT), 2x1 Combined Cycle Combustion Turbine (2x1 CCCT), and Simple Cycle Combustion Turbine (SCCT).

| | | 3x1 CCCT | 2x1 CCCT | SCCT |
|---|---|---|---|---|
| Max Capacity | MW | 900 | 640 | 190 |
| Capital Cost | $/kW | 957 | 1,136 | 700 |
| Capital Spend Profile | % | 6/42/43/9 | 6/42/43/9 | 28/61/11 |
| Fixed O&M | $/kW-yr | 36 | 51 | 170 |
| Variable O&M | $/MWh | 5 | 5 | 25 |
| Net Heat Rate | mmBTU/MWh | 7 | 7 | 11 |
| EFOR | %/Year | 5 | 5 | 6 |

### 3.2.8. Transmission

For new units, the capital cost for electric transmission to a greenfield site was assumed to be 10% of the new unit capital construction expenditures. When a new unit replaced an existing unit (and electric transmission for the existing unit's capacity was already in place), a prorated amount of transmission capital was assumed to account for any differences in capacity between the new and existing unit. Also, transmission costs were added at sites where units were retired and not replaced.

### 3.2.9. Commodity Prices

After 2016, the EPA Regulations scenario assumes generating units are required to comply physically with $SO_2$ and $NO_x$ standards. As a result, $SO_2$ and $NO_x$ allowance prices are consistent with the LTP until 2016 and then fall to zero. $CO_2$ allowance prices were assumed to be zero throughout the period, since compliance with the new regulation will be achieved through dense pack upgrades (BACT), eliminating the market for $CO_2$ allowances.

Electricity prices were updated to reflect the following changes – relative to 2010 MTP assumptions – in electricity markets: retirement of coal plants without SCRs or FGDs starting almost immediately (increase), no $CO_2$ cap and trade (decrease, particularly off-peak), no federal RPS (decrease), 3% heat rate improvement on coal units not retired for dense pack upgrades (decrease).

Coal and gas prices are consistent with 2010 MTP.

### 3.2.10. Potential Costs Not Considered

The following additional costs were not considered:

- Impact of effluent guidelines for water
- Cooling water intake structure regulations
- Coal Combustion By-Product Management regulations
- Emission controls on existing or future CCCTs or SCCTs

## 3.3. Key Uncertainties

The first key uncertainty in this scenario was whether to retire or install emission controls at Cane Run 4-6 and/or Brown 1-2. Based on the assumed capital and operating costs of each option, retiring Cane Run 4-6 (in 2016) and installing emission controls at Brown 1-2 was determined to be the optimal solution. The second uncertainty pertained to the type of unit to install in 2020 to replace Green River 3-4. Four options were considered: simple cycle combustion turbine, 2x1 combined cycle unit, 3x1 combined cycle unit, or HRSG retrofits at Trimble County combustion turbines. All Trimble County CTs were originally designed with the option to add HRSG retrofits at each of the three pairs of CTs, resulting in the potential for three 2x1 CCCTs.

## 3.4. Case Development and Analysis

The analysis of the EPA Regulations scenario was completed in two phases. In the first phase, four cases were analyzed to determine whether to retire or install emission controls at Cane Run 4-6 and/or Brown 1-2. These cases are summarized below.

- B0C0: Retire BR1-2 and CR4-6 in 2016
- B0C1: Retire BR1-2 in 2016 and install emission controls at CR4-6
- B1C0: Install emission controls at BR1-2 and retire CR4-6 in 2016
- B1C1: Install emission controls at BR1-2 and CR4-6

Based on an analysis of revenue requirements, installing emission controls at BR1-2 and retiring CR4-6 was determined to be the least-cost option. To justify the cost of emission controls at Cane Run, Cane Run would have to operate beyond 2030. Since – at most, due to landfill limitations – Cane Run can't operate beyond 2030, installing emission controls at Cane Run is not a plausible option.

The EPA Regulations scenario assumes the company will be able to reach an agreement with the EPA to allow Green River 3-4 to operate through 2019. The second phase of the analysis was developed to determine whether – if the company could reach a similar agreement for Brown 1-2 – to retire Brown 1-2 in 2020 or install emission controls in 2016. In addition, this phase determined the optimal type of unit to install in 2020 to replace Green River 3-4. This phase of the analysis includes six cases, which are summarized below:

- B0: Retire BR1-2 in 2020, replace with 2x1 or 3x1 CCCT
- B0SC: Retire BR1-2 in 2020, replace with SCCT
- B0TC: Retire BR1-2 in 2020, replace with HRSG retrofit at TC CTs
- B1: Install SCRs, Hg removal, etc on BR1-2 in 2016, add 2x1 or 3x1 CCCT in 2020
- B1SC: Install SCRs, Hg removal, etc on BR1-2 in 2016, add SCCT in 2020
- B1TC: Install SCRs, Hg removal, etc on BR1-2 in 2016, add HRSG retrofit at TC CTs in 2020

The following table shows retirements and replacements at each affected site:

| | B0 | | B0SC | | B0TC | | B1 | | B1SC | | B1TC | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Retire | Replace | Retire | Replace | Retire | Replace | Retire | Replace | Retire | Replace | Retire | Replace |
| **CR 4-6** | 2016 | 2x1 CCCT | 2016 | 2x1 CCCT | 2016 | 2x1 CCCT | 2016 | 2x1 CCCT | 2016 | 2x1 CCCT | 2016 | 2x1 CCCT |
| **GR 3-4** | 2020 | XM Fix | 2020 | SCCT | 2020 | XM Fix | 2020 | 2x1 CCCT | 2020 | SCCT | 2020 | XM Fix |
| **TY 3** | 2016 | NA | 2016 | NA | 2016 | NA | 2016 | NA | 2016 | NA | 2016 | NA |
| **BR 1-2** | 2020 | 3x1 CCCT | 2020 | SCCT (2) | 2020 | SCCT | | | | | | |

## 3.5. Results

The total net present value of revenue requirements for each case in the second phase of the analysis is listed below:

| NPVRR ($ Billion) | |
|---|---|
| B0 | 24.51 |
| B0SC | 24.53 |
| B0TC | 24.81 |
| B1 | 24.33 |
| B1SC - Recommended | 24.22 |
| B1TC | 24.77 |

The case with the lowest net present value of revenue requirements, and therefore the recommended case, was Case B1SC, in which additional emissions controls (including SNCRs, Hg removal, and biomass co-firing) were installed on Brown 1-2 in 2016, and a simple cycle combustion turbine was installed at Green River in 2020. The expansion plan for the recommended case was developed to meet energy requirements and a 14% reserve margin, and is shown below:

| 2016 | 2020 | 2021 | 2022 | 2023 | 2029 | 2036 | 2038 |
|---|---|---|---|---|---|---|---|
| 2x1 CCCT | SCCT (2) | SCCT | SCCT | 2x1 CCCT | 3x1 CCCT | SCCT | SCCT |

The components of the net present value of revenue requirements and the LTP capital expenditure plan for the recommended case are summarized below:

| NPVRR ($ Billion) | |
|---|---|
| Production Cost | 19.53 |
| New Unit Capital | 3.45 |
| Transmission Capital | 0.26 |
| Capital Savings | 0.19 |
| SCRs (GH2, MC1-2) | 0.40 |
| SNCRs (BR1-2) | 0.02 |
| FGD Upgrades (MC1-4) | 0.13 |
| Hg Removal | 0.48 |
| CO2 Efficiency | 0.13 |
| Other | 0.01 |
| **Total** | **24.22** |

| **LTP Capex ($M)** | | $ 5,975 |
|---|---|---|
| SCRs (G2, MC1, MC2) | $ 394 | |
| SNCRs (B1, B2) | 22 | |
| Incremental FGD Upgrades (MC1-4) | 78 | |
| Hg Removal | 508 | |
| CO2 Efficiency | 146 | |
| | | 1,148 |
| 2020 SCCT* | $ 180 | |
| 2021 SCCT | 59 | |
| Incremental Cost CCCT | 122 | |
| 2016 CCCT XM Savings | (63) | |
| Cane Run work not performed | (169) | |
| Tyrone work not performed | (7) | |
| Retirement Costs | 8 | |
| | | 130 |
| **Total** | | **$ 7,253** |

*The transmission cost (approximately $3 million) for the 2020 SCCT at Green River was not included.

## 3.6. Consistencies with EEI Report

On February 11, 2010, the EEI produced a report that evaluated the impact of environmental regulations on U.S. coal plants, reliability, and emissions. The conclusions from the analysis of the EPA Regulations scenario are consistent with the conclusions from the EEI report. In particular,

- For regions with high proportions of coal generation, EPA regulations will likely result in significant deterioration in regional reliability and reserve margins.

- Investments for $SO_2$, $NO_x$, & HAPs controls may ultimately become obsolete due to aggressive $CO_2$ requirements.
- Use of natural gas will increase as CCCTs replace rapid unit retirements; later retirements offer a better chance of replacement with a more balanced energy portfolio.

## 3.7. Perspectives on Interstate Natural Gas Pipeline Utilization

- In June 2009 the Rockies Express Pipeline (REX) announced service to the Lebanon Hub in Ohio, and in November the pipeline was placed into full in-service to the Clarington Hub in Monroe County, OH (see Figure 1).
- CERA has estimated that REX will displace gas flowing from the Gulf Coast to the Northeast by up to 1.8 billion cubic feet (Bcf) per day, increasing gas-on-gas competition in the Southeast, and intensifying downward pressure on the Henry Hub gas price.
- According to the EIA, the three largest pipelines delivering into the Northeast have a combined capacity of 22.5 Bcf per day: the Transcontinental Gas Pipeline Company system with 8.5 Bcf per day, the Tennessee Gas Pipeline Company with 6.7 Bcf per day, and the Texas Eastern Transmission Company with 7.3 Bcf per day. In 2009, average daily gas demand across the entire United States was ~63 Bcf, with around one-quarter of this in the NE / Mid Atlantic.
- While CERA expects REX to continue exert pressure to compress price spreads between different regions, that impact will be less noticeable under current market conditions with soft Henry Hub gas prices.
- CERA expects deliveries into Natural Gas Pipeline Company of America's southeast mainline and into Trunkline will displace gas flowing from East Texas and the Gulf Coast respectively, depressing prices in each of these regions. However he effects on Mid-Continent gas prices and flows will be temporary and are expected to unwind as REX is extended further eastward. Previously flows into the Clarington Hub were primarily from Texas Gas Transmission (Texas Gas) along with ANR's southeast mainline and the Texas Eastern Transmission Corporation (Texas Eastern) line from East Texas. The completion of REX has displaced gas flowing from the Gulf Coast into Lebanon; flows into this hub are estimated to total 2.14 Bcf per day.
- Figure 2 shows daily scheduled gas and daily capacity data for Texas Gas Transmission over the last 3-4 years. A clear increase in capacity is observable from mid-2009 – although it is not known whether this is related to the development of REX in this period.

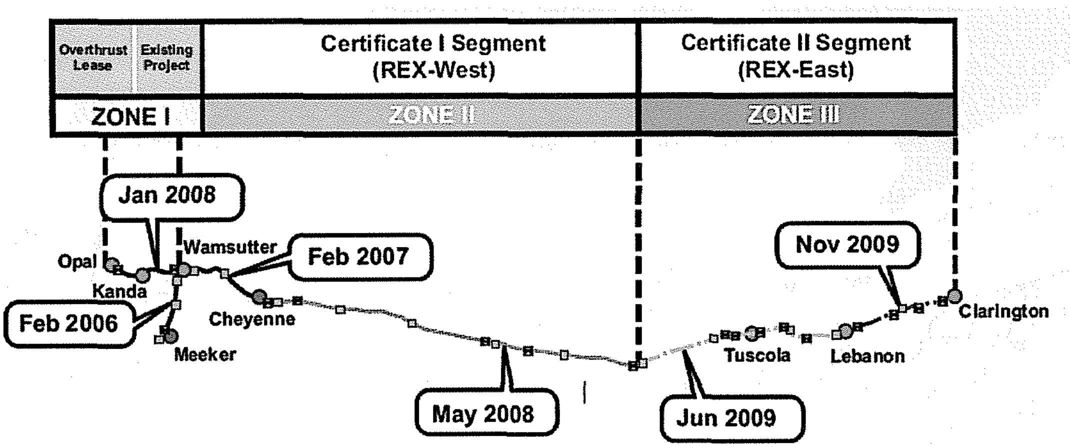



Figure 1

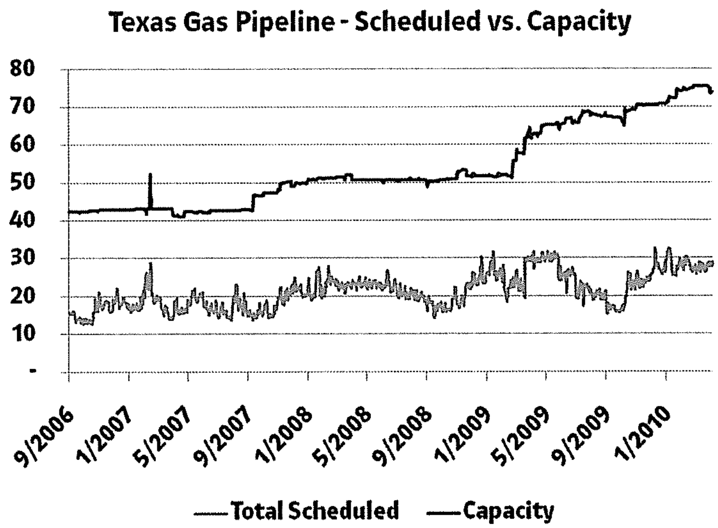



Figure 2

# 4. RPS Compromise Scenario

## 4.1. Overview

The RPS Compromise scenario does not include explicit $CO_2$ regulation, but requires a Renewable Portfolio Standard (RPS) consistent with the Waxman-Markey bill beginning in 2012. The company must meet the RPS with wind, biomass, & energy efficiency while complying with all EPA regulations in EPA Regulations scenario (except $CO_2$ BACT). Like the EPA Regulations scenario, (a) the Tyrone and Cane Run units are retired in 2016 and replaced by a combined cycle unit (at the Cane Run site) and (b) the Green River units are retired in 2020. In addition, by 2020, 1,270 MW of wind capacity and 190 MW of biomass capacity are installed to meet the RPS. More details regarding this scenario are included in the following sections.

## 4.2. Assumptions

### 4.2.1. Common Assumptions with EPA Regulations Scenario

Building from the recommended case in the EPA Regulations scenario, the following assumptions are still applicable:

- Stricter air quality standards, requiring installation or upgrades of SCRs and FGDs
- HAPS regulation, requiring precipitator upgrades and Hg removal systems
- Retire Tyrone 3 and Cane Run 4-6, install 2x1 CCCT at Cane Run in 2016
- Retire Green River 3-4 in 2020
- Costs and savings associated with retirements
- Expansion plan options
- Install SNCR and Hg removal systems on Brown 1-2 in 2016
- Install/upgrade SCRs, FGDs, and Hg removal systems in 2016 on all other units not retired
- Emission allowance prices
- Coal prices

#### 4.2.2. RPS Requirements

The RPS requirements were based on the Waxman-Markey bill, which defines renewable energy requirements and load reduction from energy efficiency programs as shown below:

| | Renewable | Efficiency | Total |
|---|---|---|---|
| 2012-2013 | 3.6% | 2.4% | 6.0% |
| 2014-2015 | 5.7% | 3.8% | 9.5% |
| 2016-2017 | 7.8% | 5.2% | 13.0% |
| 2018-2019 | 9.9% | 6.6% | 16.5% |
| 2020 + | 12.0% | 8.0% | 20.0% |

The plan to meet renewable energy requirements consists of retrofitting Ghent 1-4, Mill Creek 1-4, and Brown 3 to co-fire biomass for 5% of their total heat input in 2012, and building wind capacity and necessary transmission in 2014 and beyond. The efficiency requirement was achieved by reducing hourly load by the applicable percentages.

#### 4.2.3. Wind and Biomass

The table below shows cost assumptions for the wind capacity, which was assumed to be built in Northern Illinois or Indiana, and for biomass conversion of existing coal units:

| | | Wind | Biomass |
|---|---|---|---|
| Capital Cost | $/kW | 2100 | 2120 |
| Capital Spend Profile | % | 8/61/31 | 65/35 |
| Transmission Capital | $/kW | 200 | |
| Fixed O&M | $/kW-yr | 50 | 1.1 |
| Transmission Charge | $/MWh | 10 | |
| Fuel Cost | $/mmBTU | | 2 |

The capacity factor of the wind generation was assumed to be 31%, and only 15% of the total capacity was included in the calculation of reserve margin.

#### 4.2.4. Transmission

For new units, the capital cost for electric transmission to a greenfield site was assumed to be 10% of the new unit capital construction expenditures. When a new unit replaced an existing unit (and electric transmission for the existing unit's capacity was already in place), a prorated amount of transmission capital was assumed to account for any differences in capacity between the new and existing unit. Also, transmission costs were added at sites where units were retired and not replaced.

#### 4.2.5. Commodity Prices

Emissions allowance prices and coal prices were consistent with the EPA Regulations scenario. Gas prices and electricity prices were changed to reflect the impact of a Federal RPS on the electricity market.

#### 4.2.6. Potential Costs Not Considered

As in the EPA Regulations scenario, the following additional costs were not considered:

- Impact of effluent guidelines for water
- Cooling water intake structure regulations
- Coal Combustion By-Product Management regulations

- SCRs on existing simple cycle combustion turbines

### 4.3. Case Development and Analysis

In the RPS Compromise scenario, additional renewable generation consisted of biomass and wind. The following table shows the renewable generation required for this scenario:

| | Incremental MW | Type |
|---|---|---|
| 2012 | 190 | Biomass |
| 2014 | 275 | Wind |
| 2016 | 320 | Wind |
| 2018 | 341 | Wind |
| 2020 | 335 | Wind |

After 2020, wind capacity would grow with load to continually meet the RPS requirement.

### 4.4. Results

In addition to the incremental renewable capacity, an expansion plan was developed to meet energy requirements and a 14% reserve margin, and is shown below:

| 2016 | 2024 | 2026 | 2028 | 2029 | 2031 | 2033 | 2035 | 2037 | 2039 |
|---|---|---|---|---|---|---|---|---|---|
| 2x1 CCCT | SCCT | SCCT | SCCT | SCCT | SCCT | SCCT | SCCT | SCCT | SCCT |

The components of the net present value of revenue requirements and the LTP capital expenditure plan for the RPS Compromise scenario are summarized below:

| **NPVRR ($ Billion)** | |
|---|---|
| Production Cost | 19.26 |
| New Unit Capital | 2.37 |
| Biomass Capital | 0.47 |
| Wind Capital and Transmission | 3.40 |
| Other Transmission Capital | 0.24 |
| Capital Savings | 0.19 |
| SCRs (GH2, MC1-2) | 0.40 |
| SNCRs (BR1-2) | 0.02 |
| FGD Upgrades (MC1-4) | 0.13 |
| Hg Removal | 0.48 |
| Production Tax Credit | 0.42 |
| Other | 0.01 |
| **Total** | **26.16** |

| **LTP Capex ($M)** | | $ 5,975 |
|---|---|---|
| SCRs (G2, MC1, MC2) | $ 394 | |
| SNCRs (B1, B2) | 22 | |
| Incremental FGD Upgrades (MC1-4) | 78 | |
| Hg Removal | 518 | |
| | | 1,012 |
| Biomass | $ 403 | |
| Wind | 3,359 | |
| Incremental Cost CCGT | 122 | |
| 2016 CCCT XM Savings | (63) | |
| Other XM | 110 | |
| Cane Run work not performed | (169) | |
| Tyrone work not performed | (7) | |
| Retirement Costs | 8 | |
| | | 3,763 |
| **Total** | | **$10,750** |

## 5. $CO_2$ Intensity Cap Scenario

### 5.1. Overview

The $CO_2$ Intensity Cap scenario limits the metric tonnes of $CO_2$ per MWh generated in 2020 and beyond. The $CO_2$ intensity limits are consistent with the $CO_2$ caps proposed by Waxman-Markey

(17% below 2005 levels by 2020). The U.S. average $CO_2$ intensity in 2005 was 0.65 tonnes/MWh; the 2020 target $CO_2$ intensity is 0.54 tonnes/MWh. The average $CO_2$ intensity of E.ON U.S. generating units is currently around 0.90 tonnes/MWh; therefore, drastic changes to the generation portfolio are required in this scenario. In this scenario, all coal units are retired except TC1-2 and GH1, 3 & 4. The retired capacity is replaced with combined cycle combustion turbines and no wind. More details regarding this scenario are included in the following sections.

## 5.2. Assumptions

### 5.2.1. Common Assumptions with EPA Regulations and RPS Compromise Scenarios

Building from the recommended case in the EPA Regulations scenario and the RPS Compromise scenario, the following assumptions are still applicable:

- Stricter air quality standards, requiring installation or upgrades of SCRs and FGDs
- HAPS regulation, requiring precipitator upgrades and Hg removal systems
- Retire Tyrone 3 and Cane Run 4-6, install 2x1 CCCT at Cane Run in 2016
- Retire Green River 3-4 in 2020
- Costs and savings associated with retirements
- Expansion plan options
- Install/upgrade SCRs, FGDs, and Hg removal systems in 2016 on all other units not retired
- Load after efficiency adjustment
- Wind construction and transmission capital costs

### 5.2.2. Transmission

Transmission capital in the $CO_2$ Intensity Cap scenario was assumed to cost $200/kW of installed transmission capacity. In the cases where a new unit replaced an existing unit, the $200/kW cost was applied to the absolute difference in unit capacities. A transmission charge of $10/MWh was also included to account for firm point to point transmission. Furthermore, transmission costs were added at sites where units were retired and not replaced.

### 5.2.3. Commodity Prices

Emissions allowance prices and coal prices were consistent with the EPA Regulations and RPS Compromise scenarios. Gas prices and electricity prices were changed to reflect the impact of a $CO_2$ intensity cap on the electricity market.

### 5.2.4. Potential Costs Not Considered

As in the EPA Regulations scenario, the following additional costs were not considered:

- Impact of effluent guidelines for water
- Cooling water intake structure regulations
- Coal Combustion By-Product Management regulations
- SCRs on existing simple cycle combustion turbines

## 5.3. Case Development and Analysis

A linear program was developed to determine the least-cost combination of coal unit retirements, new wind capacity, and new combined cycle units to meet the $CO_2$ intensity cap in 2020. The program determined the least-cost combination of these options while ensuring that enough energy was produced to meet load, a 14% reserve margin was maintained, and the $CO_2$ intensity target was met. Because wind contributes relatively little towards a reserve margin calculation, the optimal solution for meeting the intensity target was to replace retired coal with combined cycle units and no wind. After this case was developed, two additional cases were developed: RPS Wind and High Wind.

The RPS Wind case has the same amount of wind capacity as the RPS Compromise scenario. While this case is not least-cost, fewer coal units are retired in the RPS Wind case compared to the recommended 'No Wind' case. In the 'High Wind' case, enough additional wind generation is installed to avoid retiring one coal unit (Mill Creek 3). The table below summarizes the coal unit retirements, new wind capacity, and new combined cycle units in each of the three wind scenarios. The net present value of revenue requirements is also included. In all cases, Cane Run 4-6 and Tyrone 3 are retired in 2016 and replaced by a combined cycle unit at the Cane Run site. All other retirements and capacity additions are assumed to occur in 2020.

| | Wind (MW) | CCCT (MW) | Coal Retired (MW) | NPVRR ($B) |
|---|---|---|---|---|
| No Wind – Recommended | 0 | 3,200 (5 CCCT: 2xMC, 1xBR, 1xGH, 1xCR) | -3,450 (CR, TY, GR, BR, MC, GH2) | 30.0 |
| RPS Wind | 1,270 | 2,560 (4 CCCT: 2xMC, 1xBR, 1xCR) | -2,966 (CR, TY, GR, BR, MC) | 30.7 |
| High Wind | 2,150 | 1,920 (3 CCCT: 1xMC, 1xBR, 1xCR) | -2,575 (CR, TY, GR, BR, MC1,2,4) | 30.8 |

### 5.3.1. Modified Capacity Factor

The results of the linear program were verified using Strategist. In order to meet the $CO_2$ intensity cap and retire as few coal units as possible, the capacity factor in Strategist was adjusted so that the CCCTs were dispatched more frequently than was strictly economical.

## 5.4. Results

The total net present value revenue requirement for each case is listed below:

| NPVRR ($ Billion) | |
|---|---|
| No Wind - Recommended | 30.0 |
| RPS Wind | 30.7 |
| High Wind | 30.8 |

The case with the least revenue requirements, and therefore the recommended case, was the No Wind case.

The chart below shows the adjusted capital budget for the $CO_2$ Intensity Cap recommended case. The savings result from changes to the LTP, including cancelled scheduled maintenance, major replacements (precipitators, stator and generator rewind), landfills, and ash ponds.

| Capital Savings ($M) | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 |
|---|---|---|---|---|---|---|---|---|---|---|
| Tyrone 3 | 0 | 0 | 0 | 0 | 0 | 0 | (2) | (2) | (2) | (2) |
| Brown 1-3 | 0 | 0 | 0 | 0 | 0 | (1) | (5) | (5) | (5) | (7) |
| Cane Run 4-6 | 0 | 0 | 0 | 0 | (0) | (6) | (28) | (20) | (24) | (25) |
| Ghent 1-4 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | (2) | (2) |

The expansion plan for the recommended case was developed to meet energy requirements and a 14% reserve margin, and is shown below:

| 2016 | 2020 | 2022 | 2024 | 2025 | 2027 | 2029 | 2031 | 2033 | 2034 | 2036 | 2038 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 2x1 CCCT | 2x1 CCCT (4) | SCCT | SCCT | SCCT | SCCT | SCCT | SCCT | SCCT | SCCT | SCCT | SCCT |

The components of the net present value of revenue requirements and the LTP capital expenditure plan for the recommended case are summarized below:

| **NPVRR ($ Billion)** | |
|---|---|
| Production Cost | 25.04 |
| New Unit Capital | 5.25 |
| Transmission Capital | 0.16 |
| Capital Savings | 0.65 |
| Hg Removal | 0.22 |
| Retirement Expense | 0.02 |
| **Total** | **30.04** |

| **LTP Capex ($M)** | | $ 5,975 |
|---|---|---|
| Hg Removal | 235 | |
| | | 235 |
| 2020 CCCT (4) | $ 4,006 | |
| Incremental Cost CCGT | 122 | |
| 2016 CCCT XM Savings | (61) | |
| Other XM | 228 | |
| Cane Run work not performed | (169) | |
| Tyrone work not performed | (7) | |
| Ghent work not performed | (4) | |
| Brown work not performed | (22) | |
| Mill Creek work not performed | (54) | |
| Retirement Costs | 8 | |
| | | 4,047 |
| **Total** | | **$ 10,257** |

# 6. Appendices

## 6.1. EPA Regulations Scenario Presentation
## 6.2. Scenario Update – RPS Compromise and $CO_2$ Intensity Scenarios
## 6.3. Final Presentation

# EPA Regulations Scenario

Financial Planning and Generation Planning & Analysis
March 10, 2010

# EPA Regulations Scenario

- Assumes extension of compliance timeline
  - Required environmental controls installed by Jan 2016
  - Selected unit retirements delayed until 2020
- Removed 150 MW of industrial load from LTP
- Current municipal contracts (400 MW) remain in place
- Tyrone and Cane Run retired in 2016; Green River in 2020
- 640 MW Combined cycle unit replaces Cane Run in 2016
- New capacity in 2020 is scaled to replace Green River and serve load growth
- Key Uncertainties
  - Brown 1-2 are retrofitted with less expensive SNCRs instead of SCRs
  - 2020 capacity additions: either a CCCT or simple cycle CTs

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# Why retire Cane Run in 2016?

- Cane Run must operate beyond 2030 to justify additional emission controls and other investments
  - Future CO2 regulations, including potential carbon capture/sequestration, are uncertain
- CCCT capacity approximates Cane Run (640 MW vs. 560 MW)
- Timeline for permitting, transmission, gas interconnection is expected to be streamlined at Cane Run site

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# Capex ($M)

| | | |
|---|---|---|
| LTP Capex | | $ 5,975 |
| SCRs (G2, MC1, MC2) | $ 394 | |
| SNCRs (B1, B2) | 22 | |
| Incremental FGD Upgrades (MC1-4) | 78 | |
| Hg Removal | 508 | |
| CO2 Efficiency | 146 | |
| | | 1,148 |
| 2020 SCCT | $ 180 | |
| 2021 SCCT | 59 | |
| Incremental Cost CCGT | 122 | |
| XM Savings | (63) | |
| Cane Run work not performed | (169) | |
| Tyrone work not performed | (7) | |
| Retirement Costs | 8 | |
| | | 130 |
| EPA Reg Alternative 1 | | $ 7,253 |
| CCGT vs SCCTs | $ 762 | |
| SCR vs SNCR | 157 | |
| Incremental XM | 66 | |
| | | 985 |
| EPA Reg Alternative 2 | | $ 8,238 |

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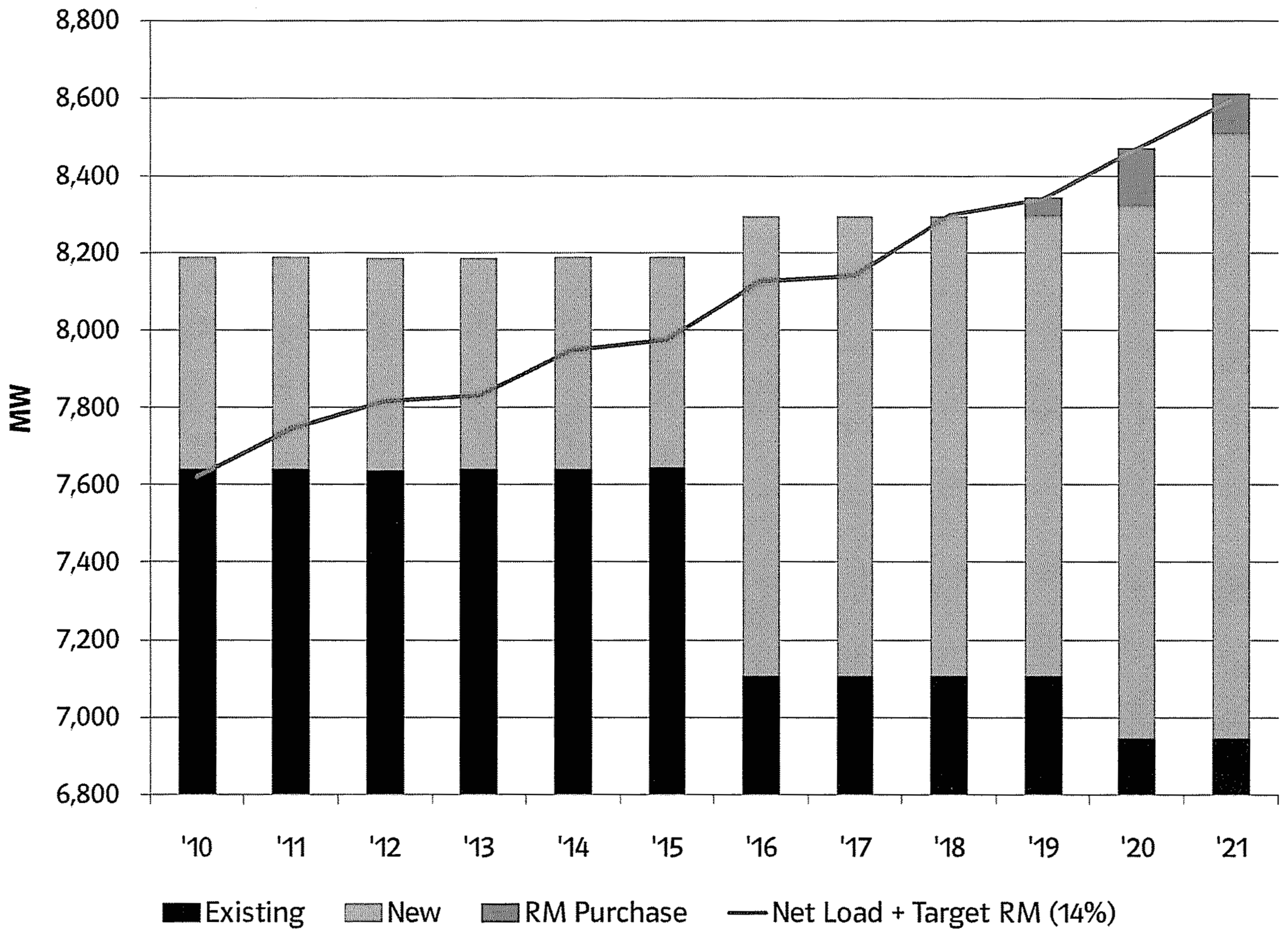
# Reserve margin purchases are needed at end of LTP period




| *MW* | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Reserve Margin Surplus/(Need) | 572 | 446 | 372 | 357 | 244 | 218 | 173 | 155 | (3) | (44) | (150) | (78) |

# Financial Impact Summary

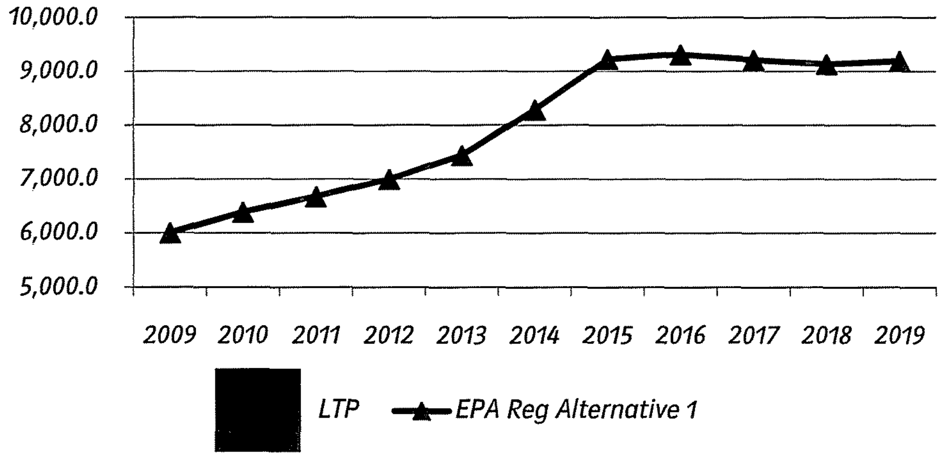
- Incremental Capex of $1.3B leads to $1.2B increase in Utility Capitalization
- Become FCF positive in 2016 vs 2014
- EBIT , on average, about $100M/year higher in back half of LTP

| | |
|---|---|
| Higher Revenues | $ 42 |
| Removal of CO2 Allowance Costs | 238 |
| Higher Fuel Costs | (156) |
| Depreciation | (25) |
| EBIT | $ 99 |

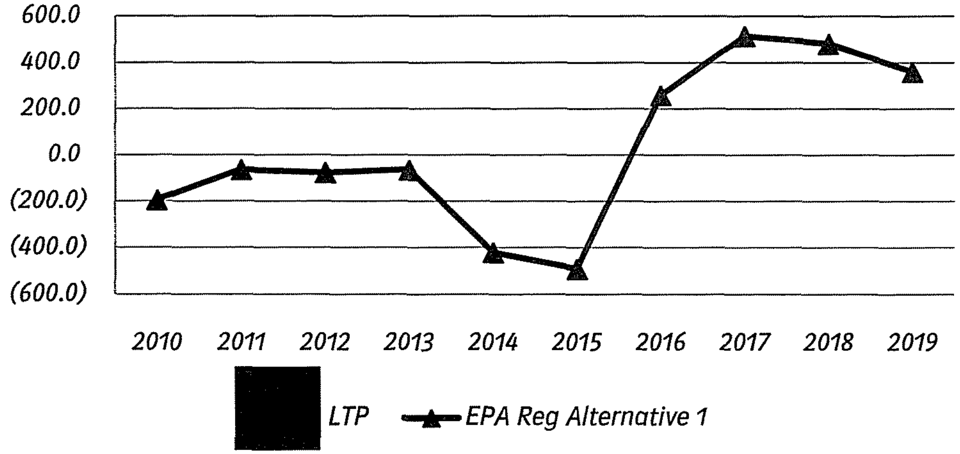
- 10 year CAGR for Retail Rates largely unaffected e·on | U.S. **LTP data redacted as non-responsive**

# LTP Financial Story – Base vs. EPA Regulation Scenario

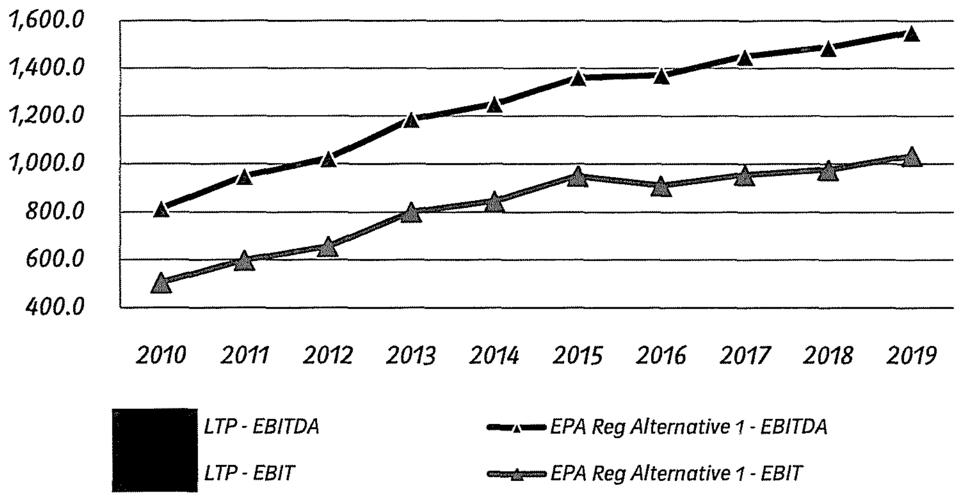
## Growth in Utility Capitalization...



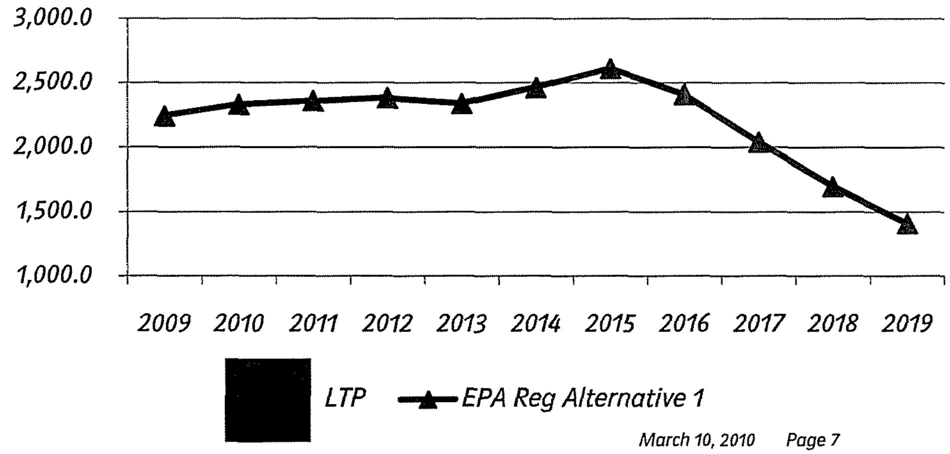

## ...Improves Cash Flows...



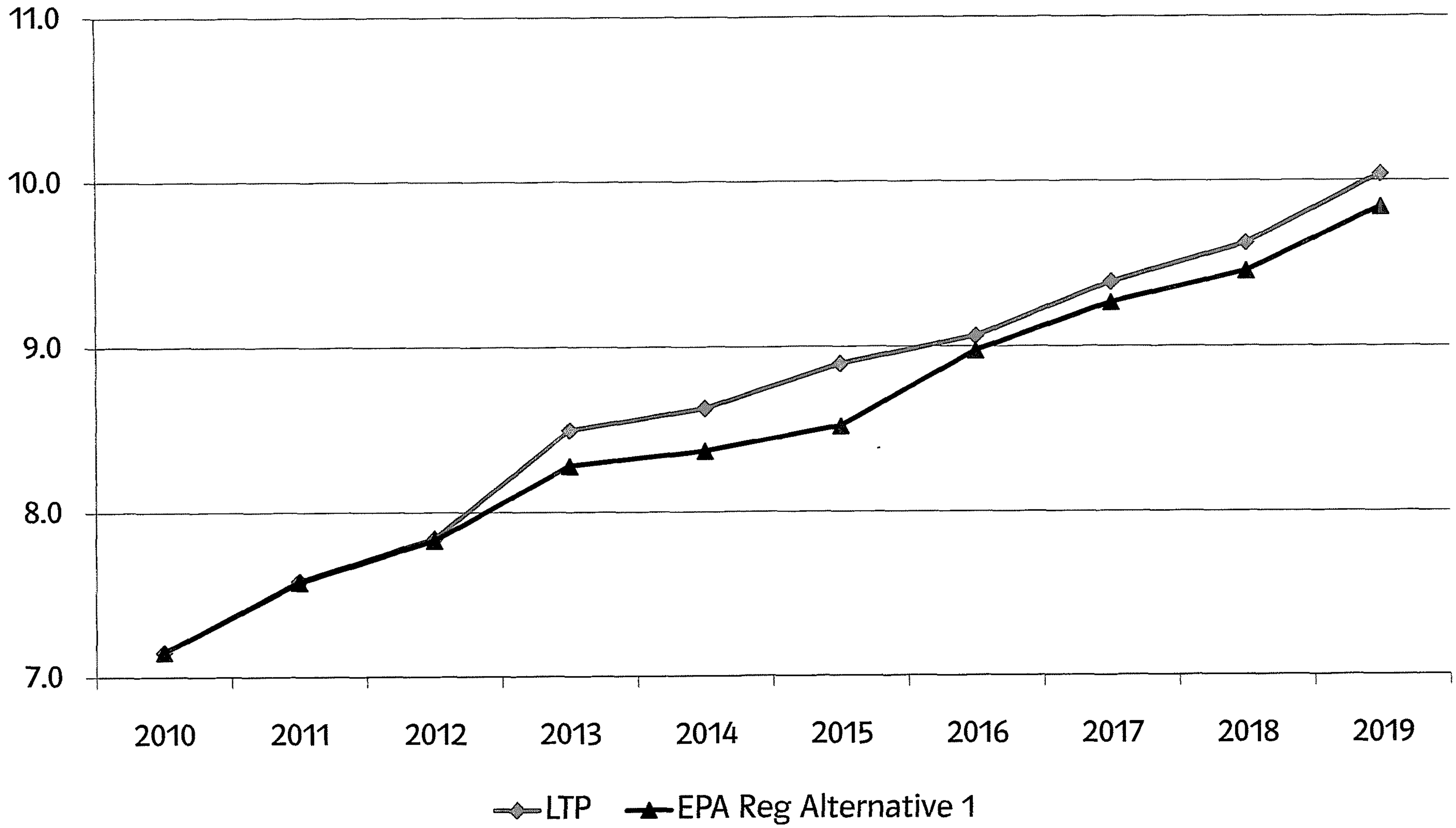

## ...Leads to Increased Earnings...




## ...Reduces Holding Company Debt



# Retail Rate Progression ($)



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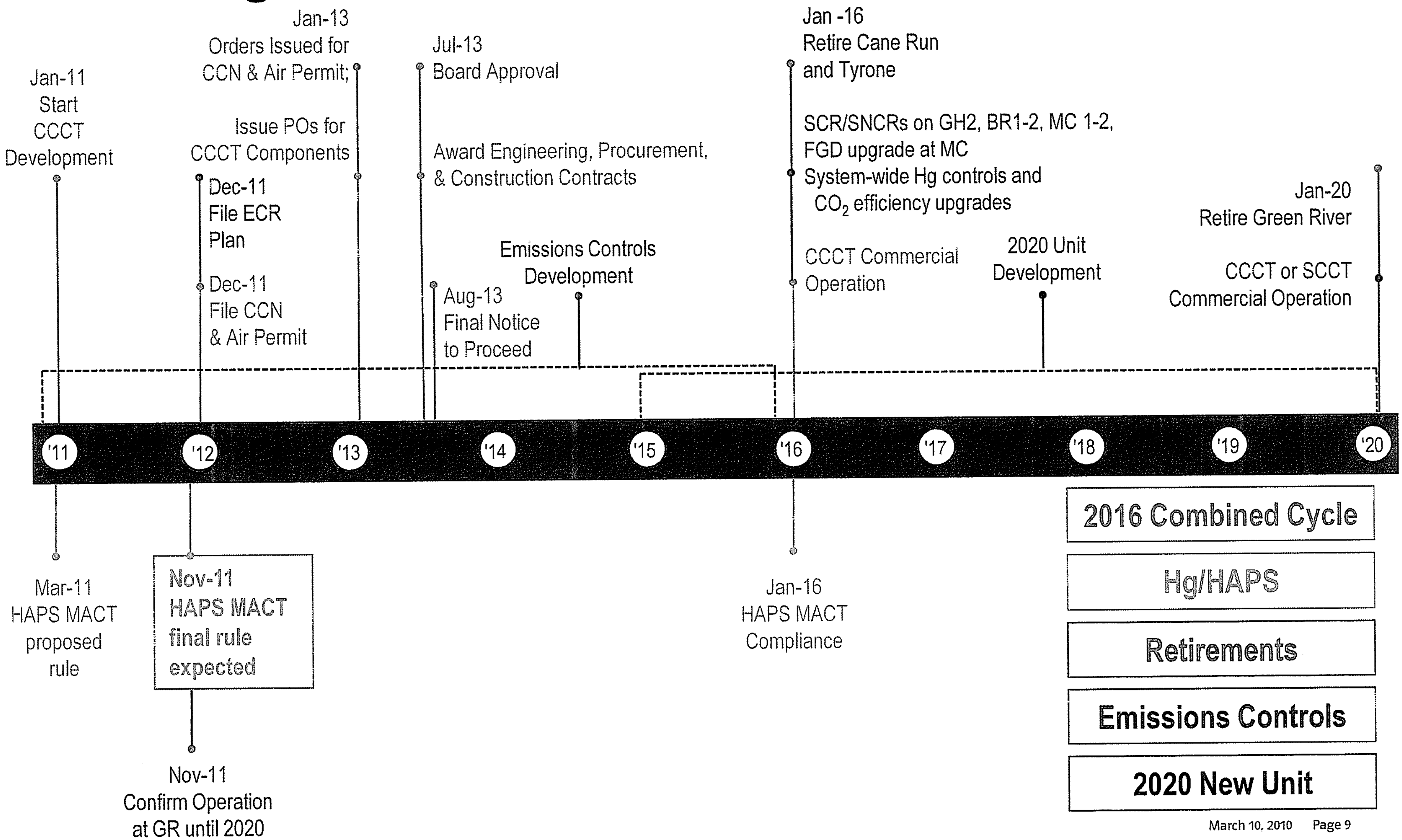
# EPA Regulations – Extended Timeline



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# Scenario Update – RPS Compromise and $CO_2$ Intensity Scenarios

Generation Planning & Analysis

March 29, 2010

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# Overview of scenarios

| Assumptions | EPA Extended | RPS Compromise | CO2 Intensity Cap |
|---|---|---|---|
| Retire CR, TY 2016 (replace with CCCT); Retire GR 2020 | ✓ | ✓ | ✓ |
| HAPS, $SO_2$ and $NO_X$ regs require FGDs and SCRs on remaining units (SNCR on BR1-2*) | ✓ | ✓ | ✓ |
| No new industrial customer | ✓ | ✓ | ✓ |
| LTP coal prices; LTP EA prices for $SO_2$ and $NO_x$ through 2015; No $CO_2$ allowance prices | ✓ | ✓ | ✓ |
| Gas/Electricity Prices | LTP Gas<br>Higher Elec. | Slightly lower vs. EPA<br>(Efficiency) | Slightly higher vs. EPA<br>($CO_2$ requirements & rush to gas) |
| Load Forecast (Maintain municipal contracts) | LTP | Lower vs. EPA<br>(Efficiency) | Lower vs. EPA<br>(Efficiency) |
| RPS Requirement | | ✓ | |
| CO2 Intensity Cap | | | ✓ |

*SNCR may not be sufficient to meet $NO_x$ limits.

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# New-build cost assumptions

| *2010$* | | Biomass | Wind | CCCT |
|---|---|---|---|---|
| Capital | *$/kW* | 2,120 | 2,100<br>+200 XM | 1,136 |
| Fixed O&M | *$/kW-yr* | 1.10 | 50 | 34 |
| Variable O&M | *$/MWh* | 0 | 10 (XM) | 5 |
| Fuel Cost | *$/mmBTU* | 2 | -- | Gas |
| Production Tax Credit | *$/MWh* | 10 | 21 | -- |

- Biomass is 5% cofire and is limited by fuel supply to 190 MW
- Wind is assumed to be company-owned (cost is comparable to purchase)
- 15% of wind capacity counts toward reserve margin
- CCCTs require XM capital of $200/kW on building more/less capacity to replace retirements

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# RPS Compromise scenario

Objective: meet RPS with wind, biomass, & energy efficiency while complying with all EPA regulations in Extended EPA Regulations scenario <u>except</u> $CO_2$ BACT.

Waxman-Markey guidelines for RPS: 20% by 2020 with 40% allowed from energy efficiency

| Energy Reduction (%) | Renewables | Efficiency | Total |
|---|---|---|---|
| 2012-2013 | 3.6 | 2.4 | 6.0 |
| 2014-2015 | 5.7 | 3.8 | 9.5 |
| 2016-2017 | 7.8 | 5.2 | 13.0 |
| 2018-2019 | 9.9 | 6.6 | 16.5 |
| 2020+ | 12.0 | 8.0 | 20.0 |

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# RPS Compromise plan includes 1,270 MW of wind capacity

## Annual Impacts to Capacity (MW)

| | Efficiency | Biomass* | Wind | Retire | New CCCT |
|---|---|---|---|---|---|
| 2012** | 165 | 190 | - | - | - |
| 2013 | - | - | - | - | - |
| 2014 | 101 | - | 275 | - | - |
| 2015 | - | - | - | - | - |
| 2016 | 106 | - | 320 | -634 (CR, TY) | 640 (CR) |
| 2017 | - | - | - | - | - |
| 2018 | 111 | - | 341 | - | - |
| 2019 | - | - | - | - | - |
| 2020 | 112 | - | 334 | -163 (GR) | - |
| **Cum. Total** | **595** | **190** | **1,270** | **-797** | **640** |

*190 MW of existing capacity is converted to biomass cofire. Includes provision for landfill gas.
**Compliance by 2012 would likely only be achievable with a wind power purchase.

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# $CO_2$ Intensity Cap scenario

Objective: achieve $CO_2$ intensity target of 0.54 tonnes/MWh in 2020 by retiring coal and adding CCCT/wind.

Target is 17% below 2005 national average level.

| | Current E.ON U.S. Average | E.ON U.S. Coal Units | New SCCT | New CCCT | Wind |
|---|---|---|---|---|---|
| **$CO_2$ Intensity** ***(MT/MWh)*** | ~0.9 | 0.8 - 1.0 | 0.6 | 0.4 | 0 |

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# Least-cost $CO_2$ Intensity Cap plan is to retire all coal except TC1-2 and GH1,3,4, replacing with CCCT and no wind

## Annual Impacts to Capacity (MW)

| | Efficiency | Wind | Retire | New CCCT |
|---|---|---|---|---|
| 2012 | 165 | - | - | - |
| 2013 | - | - | - | - |
| 2014 | 101 | - | - | - |
| 2015 | - | - | - | - |
| 2016 | 106 | - | -634 (CR, TY) | 640 (CR) |
| 2017 | - | - | - | - |
| 2018 | 111 | - | - | - |
| 2019 | - | - | - | - |
| 2020 | 112 | - | -2,816 (GR, BR, MC, GH2) | 2,560 (4 CCCT: 2xMC, 1xBR, 1xGH) |
| **Cum. Total** | **595** | **0** | **-3,450** | **3,200** |

# Including wind in CO2 Intensity scenario results in higher revenue requirements

| | Wind (MW) | CCCT (MW) | Coal Retired (MW) | PVRR ($B) |
|---|---|---|---|---|
| No Wind | 0 | 3,200 (5 CCCT: 2xMC, 1xBR, 1xGH, 1xCR) | -3,450 (CR, TY, GR, BR, MC, GH2) | 30.0 |
| RPS Wind | 1,270 | 2,560 (4 CCCT: 2xMC, 1xBR, 1xCR) | -2,966 (CR, TY, GR, BR, MC) | 30.7 |
| High Wind | 2,150 | 1,920 (3 CCCT: 1xMC, 1xBR, 1xCR) | -2,575 (CR, TY, GR, BR, MC1,2,4) | 30.8 |

- Low contribution to reserve margin and high capital costs result in eliminating wind from generation mix.
- Base PVRR includes emissions allowances costs through study period.

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# Environmental Scenario Analysis

Financial Planning and Generation Planning & Analysis
April 19, 2010

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# EPA Regulations Scenario

- Assumes extension of compliance timeline
  - Required environmental controls installed by Jan 2016
  - Selected unit retirements delayed until 2020
- Removed 150 MW of industrial load from LTP
- Current municipal contracts (400 MW) remain in place
- Tyrone and Cane Run retired in 2016; Green River in 2020
- 640 MW Combined cycle unit replaces Cane Run in 2016
- New capacity in 2020 is scaled to replace Green River and serve load growth
- Key Uncertainties
  - Brown 1-2 are retrofitted with less expensive SNCRs instead of SCRs
  - 2020 capacity additions: either a CCCT or simple cycle CTs

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# Overview of scenarios

| Assumptions | EPA Regulations | RPS Compromise | CO2 Intensity Cap |
|---|---|---|---|
| Retire CR, TY 2016 (replace with CCCT); Retire GR 2020 | ✓ | ✓ | ✓ |
| HAPS, $SO_2$ and $NO_X$ regs require FGDs and SCRs on remaining units (SNCR on BR1-2*) | ✓ | ✓ | ✓ |
| No new industrial customer | ✓ | ✓ | ✓ |
| LTP coal prices; LTP EA prices for $SO_2$ and $NO_x$ through 2015; No $CO_2$ allowance prices | ✓ | ✓ | ✓ |
| Gas/Electricity Prices | LTP Gas<br>Higher Elec. | Slightly lower vs. EPA<br>(Efficiency) | Slightly higher vs. EPA<br>($CO_2$ requirements & rush to gas) |
| Load Forecast (Maintain municipal contracts) | LTP | Lower vs. EPA<br>(Efficiency) | Lower vs. EPA<br>(Efficiency) |
| RPS Requirement | | ✓ | |
| CO2 Intensity Cap | | | ✓ |

*SNCR may not be sufficient to meet $NO_x$ limits.

# RPS Compromise scenario

- Objective: meet RPS with wind, biomass, & energy efficiency while complying with all EPA regulations in EPA Regulations scenario <u>except</u> $CO_2$ BACT
- Waxman-Markey guidelines for RPS: 20% by 2020 with 40% allowed from energy efficiency (i.e., 12% renewables, 8% energy efficiency)
- Tyrone and Cane Run still retired in 2016; Green River in 2020. 640 MW Combined cycle unit replaces Cane Run in 2016
- Energy efficiency gains eliminate need for additional gas generation in 2020
- 1,270 MW of wind capacity is installed by 2020 to meet RPS

# $CO_2$ Intensity Cap scenario

- Objective: achieve $CO_2$ intensity target of 0.54 tonnes/MWh in 2020 by retiring coal and adding CCCT/wind
- Intensity target is 17% below 2005 national average level
- Tyrone and Cane Run still retired in 2016; Green River in 2020. 640 MW Combined cycle unit replaces Cane Run in 2016
- **Least-cost $CO_2$ Intensity Cap plan is to retire all coal except TC1-2 and GH1,3,4, replacing with CCCT and no wind**
- 4 CCCTs are installed in 2020 to meet $CO_2$ intensity target – majority of rate impact is deferred beyond LTP period

| | Current E.ON U.S. Average | E.ON U.S. Coal Units | New SCCT | New CCCT | Wind |
|---|---|---|---|---|---|
| **$CO_2$ Intensity** ***(MT/MWh)*** | ~0.9 | 0.8 - 1.0 | 0.6 | 0.4 | 0 |

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# Capex ($M)

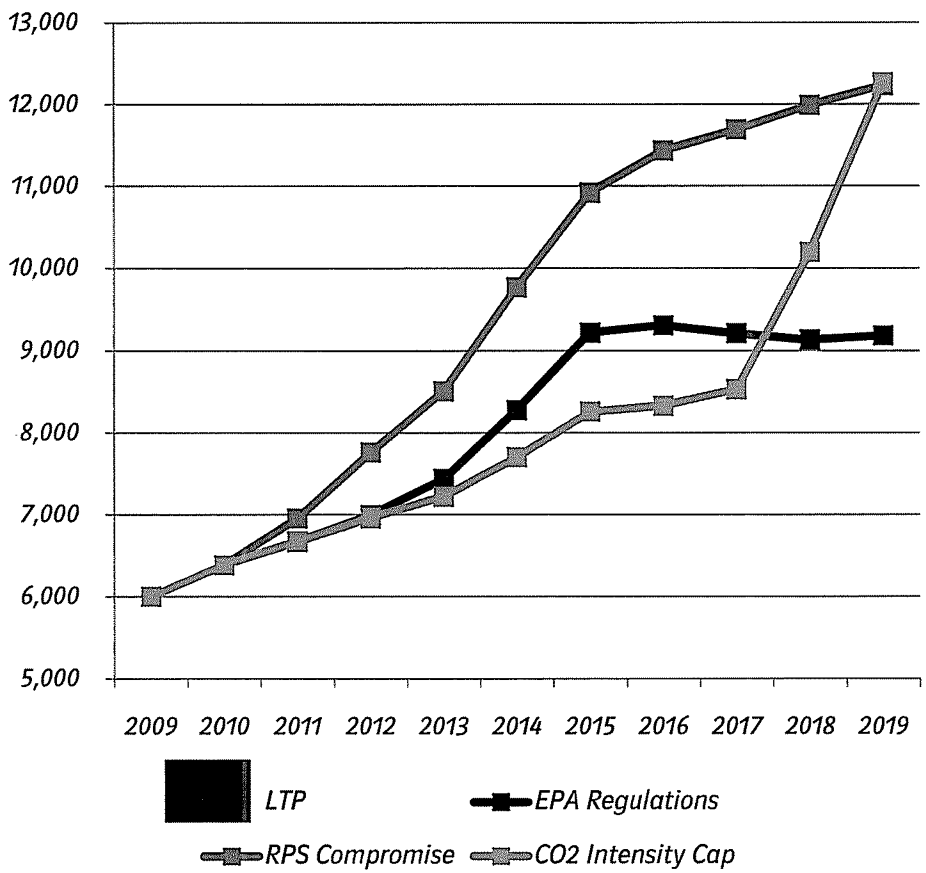
| | EPA Regulations | RPS Compromise | CO2 Intensity Cap |
|---|---|---|---|
| LTP Capex | $ 5,975 | $ 5,975 | $ 5,975 |
| | | | |
| SCRs (GH2, MC1, MC2) | $ 394 | $ 394 | $ - |
| SNCRs (B1, B2) | 22 | 22 | - |
| Incremental FGD Upgrades (MC1-4) | 78 | 78 | (54) |
| Hg Removal | 508 | 518 | 235 |
| CO2 Efficiency | 146 | - | - |
| | $ 1,148 | $ 1,012 | $ 181 |
| | | | |
| New Units [1] | $ 239 | $ 3,764 | $ 4,007 |
| Incremental Cost CCCT [2] | 122 | 122 | 122 |
| XM Savings | (63) | (63) | (63) |
| Work not performed | (176) | (176) | (202) |
| Retirement Costs | 8 | 8 | 8 |
| Other XM | - | 110 | 230 |
| | $ 130 | $ 3,765 | $ 4,102 |
| | | | |
| Total Alternative 1 | $ 7,253 | $ 10,752 | $ 10,258 |
| | | | |
| CCCT vs. SCCTs | $ 762 | $ - | $ - |
| SCR vs. SNCR | 157 | 157 | - |
| Incremental XM | 66 | - | - |
| | $ 985 | $ 157 | $ - |
| | | | |
| Total Alternative 2 | $ 8,238 | $ 10,909 | $ 10,258 |

[1] EPA Regulations: 2020 SCCT - 190 MW, 2021 SCCT - 190 MW
RPS Compromise: 2020 (4) CCCT - 640 MW/unit
CO2 Intensity Cap: 2014 Wind - 275 MW, 2016 Wind - 320 MW, 2018 Wind - 341 MW, 2010 Wind - 335 MW; Biomass
[2] 640 MW CCCT (2016) compared to 533 MW (2017) in the LTP

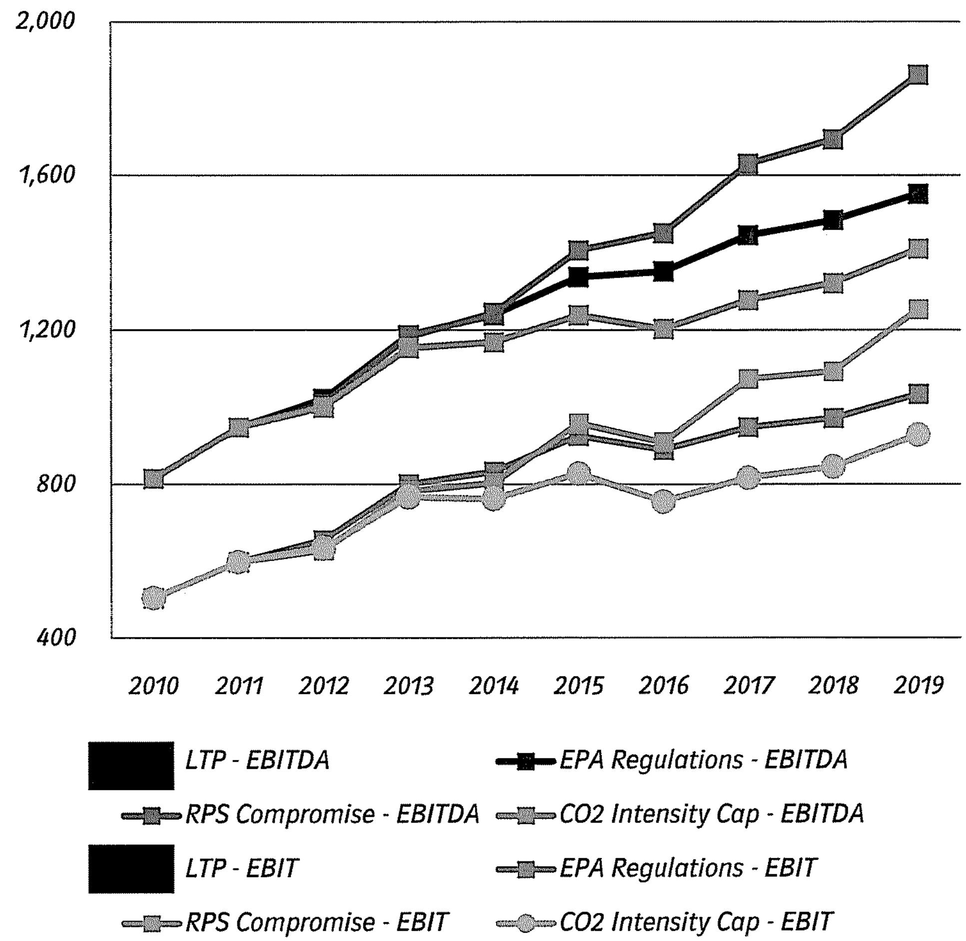
LTP data redacted as non-responsive

# Financials

## Utility Capitalization ($M)




## Earnings ($M)



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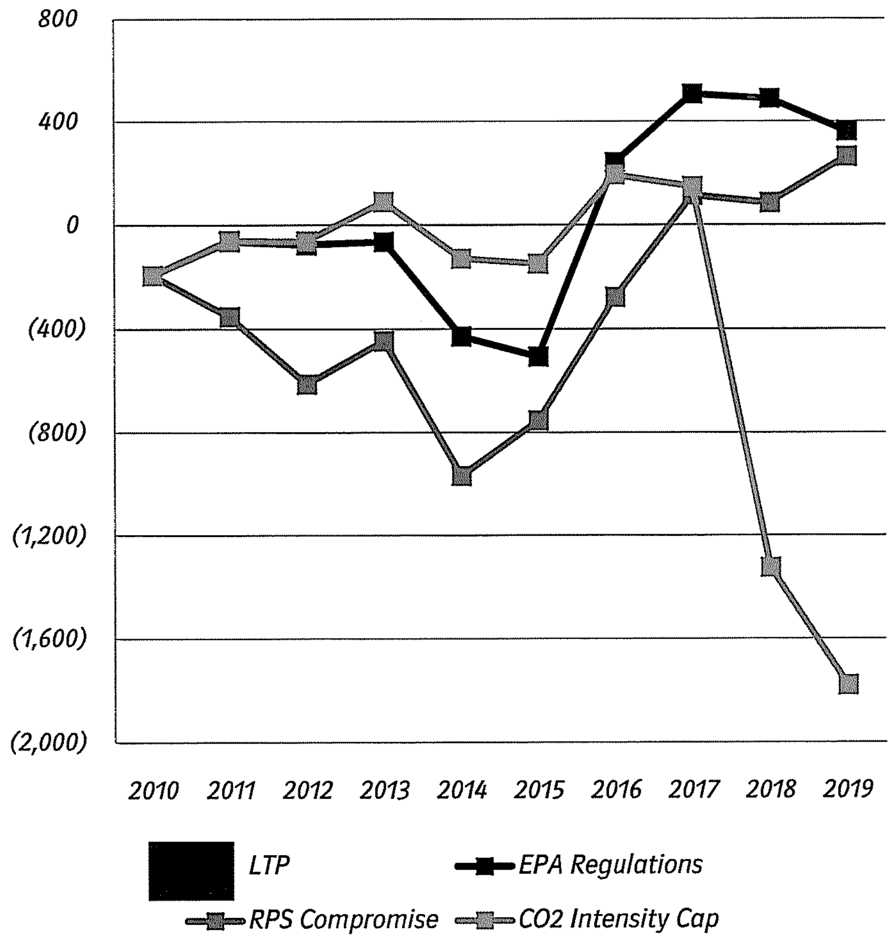
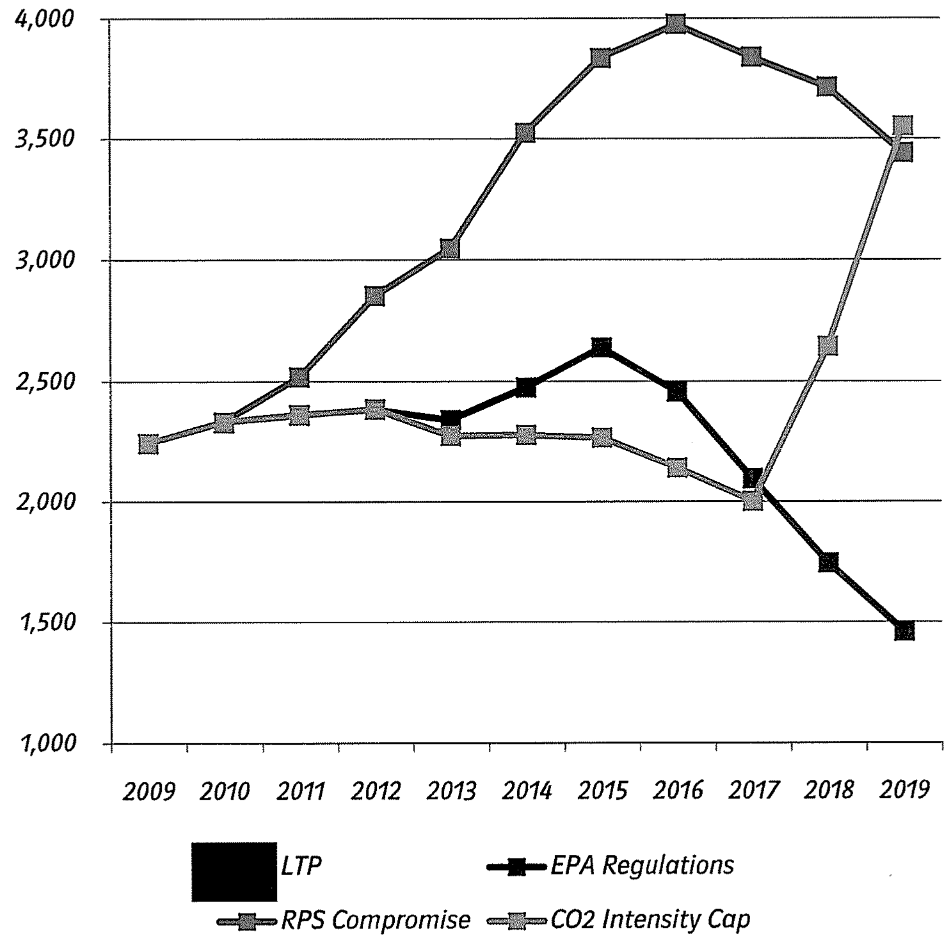
# LTP data redacted as non-responsive

## Financials

### Free Cash Flows ($M)




### Holding Company Debt ($M)



# Appendix

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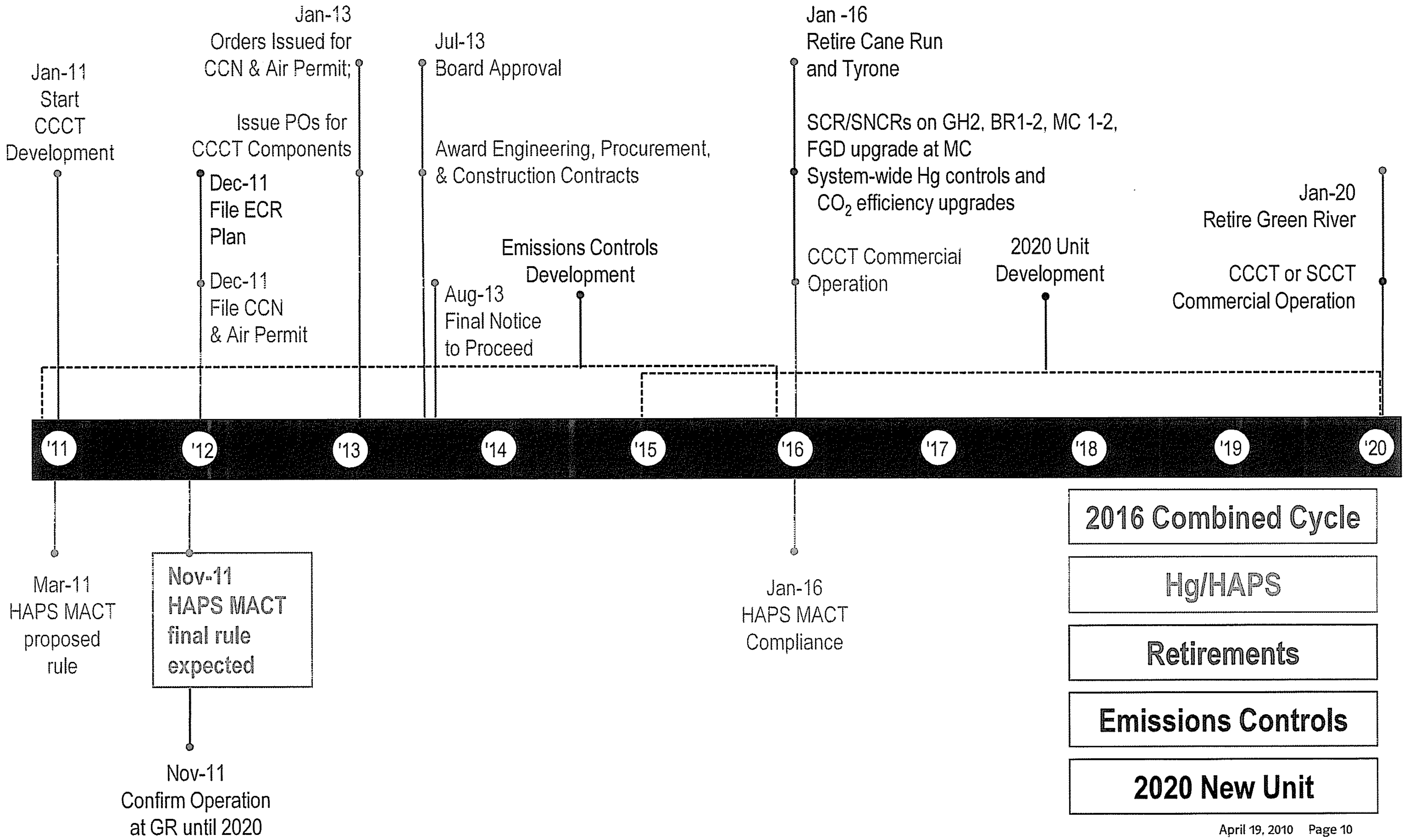
# EPA Regulations – Extended Timeline



# Why retire Cane Run in 2016?

- Cane Run must operate beyond 2030 to justify additional emission controls and other investments
  - Future CO2 regulations, including potential carbon capture/sequestration, are uncertain
- CCCT capacity approximates Cane Run (640 MW vs. 560 MW)
- Timeline for permitting, transmission, gas interconnection is expected to be streamlined at Cane Run site

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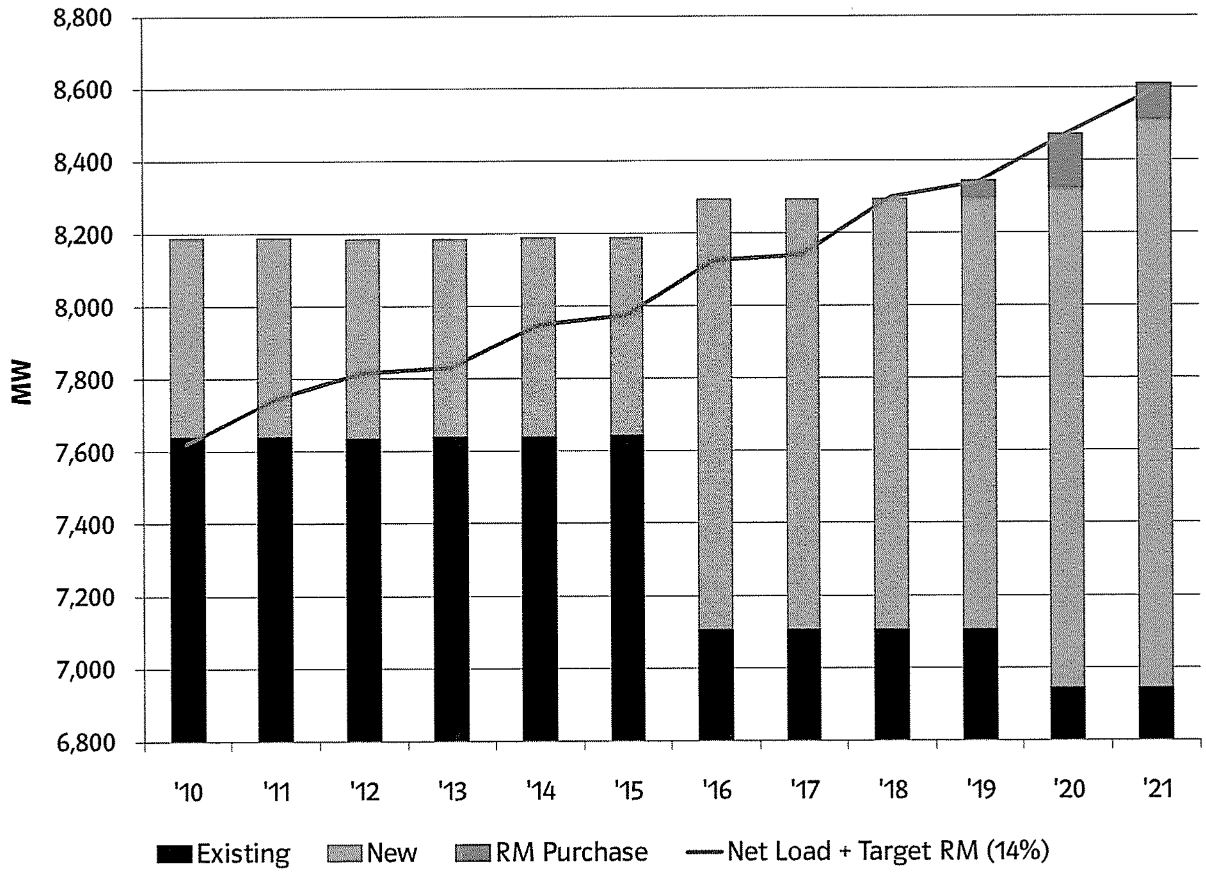
# EPA Regulations Scenario: Reserve margin purchases are needed at end of LTP period




| *MW* | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Reserve Margin Surplus/(Need) | 572 | 446 | 372 | 357 | 244 | 218 | 173 | 155 | (3) | (44) | (150) | (78) |

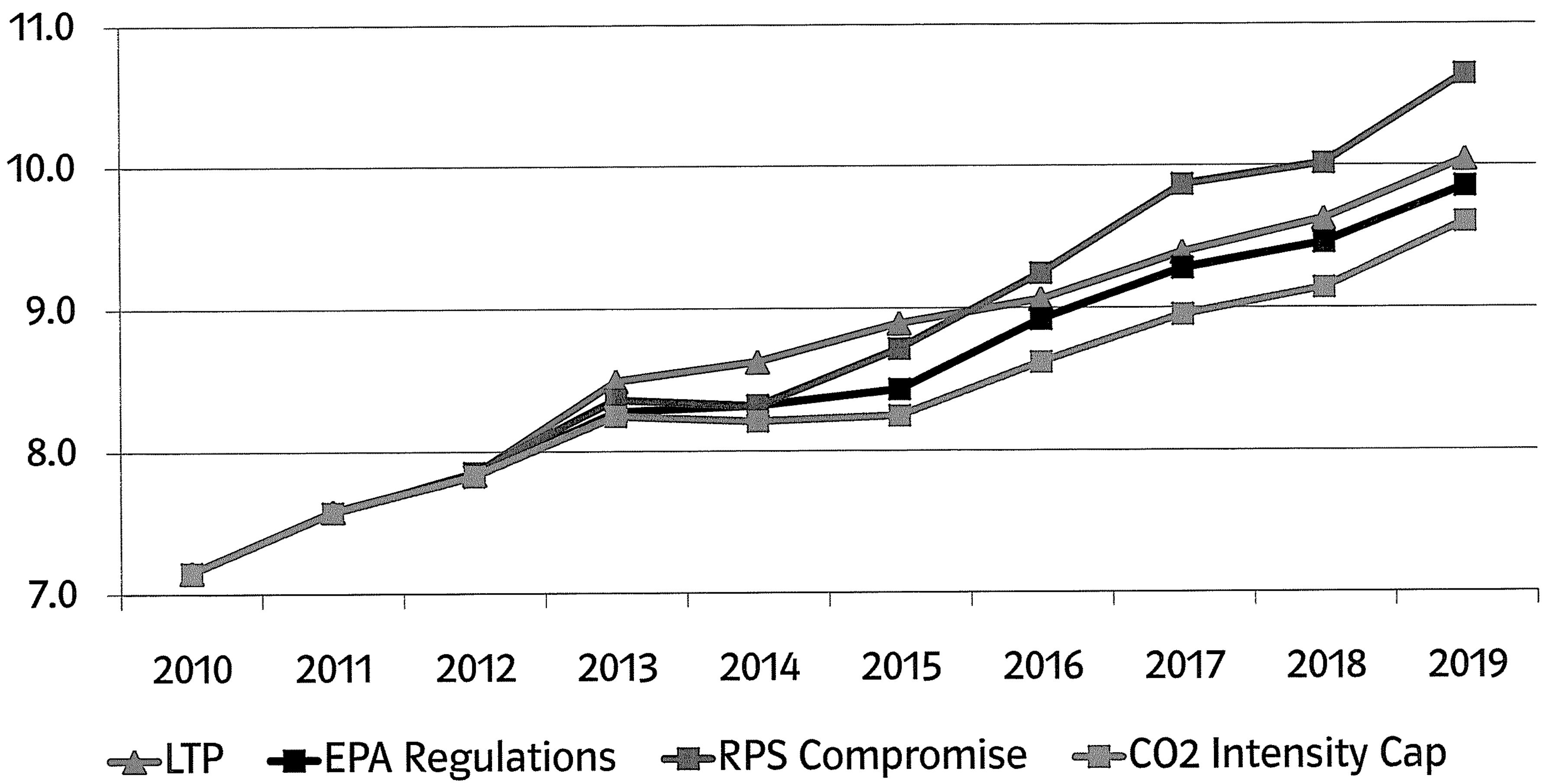
# EPA Regulations Scenario: Financial Impact Summary

| | LTP | EPA Regulation | RPS Compromise | CO2 Intensity Cap |
|---|---|---|---|---|
| Incremental Capex vs. LTP ($M) | | 1,270 | 4,768 | 4,275 |
| Incremental Utility Capitalization vs. LTP ($M) | | 1,186 | 4,234 | 4,269 |
| EBIT [1] | | | | |
| Lower Revenue | | (59) | (23) | (236) |
| Removal of CO2 Allowances | | 283 | 283 | 283 |
| Other Cost of Sales | | (45) | (57) | (17) |
| Fuel Cost | | (66) | 84 | (61) |
| Depreciation | | (25) | (97) | (1) |
| EBIT | | 88 | 190 | (32) |
| FCF positive | 2014 | 2016 | 2017 | N/A |
| 10 Year CAGR for Retail Rates | 3.84% | 3.63% | 4.52% | 3.33% |

**Significant stranded investment in CO2 Intensity Cap Scenario outside the LTP window. Capex spend on retired units would need to be reevaluated.**

[1] Average impact last 5 years of LTP

## Retail Rate Progression (cents/kWh)




*Majority of rate impact in $CO_2$ Intensity Cap scenario is deferred beyond LTP period.

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# New-build cost assumptions

| *2010$* | | Biomass | Wind | CCCT |
|---|---|---|---|---|
| Capital | *$/kW* | 2,120 | 2,100 +200 XM | 1,136 |
| Fixed O&M | *$/kW-yr* | 1.10 | 50 | 34 |
| Variable O&M | *$/MWh* | 0 | 10 (XM) | 5 |
| Fuel Cost | *$/mmBTU* | 2 | -- | Gas |
| Production Tax Credit | *$/MWh* | 10 | 21 | -- |

- Biomass is 5% cofire and is limited by fuel supply to 190 MW
- Wind is assumed to be company-owned (cost is comparable to purchase)
- 15% of wind capacity counts toward reserve margin
- CCCTs require XM capital of $200/kW on building more/less capacity to replace retirements

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- Low contribution to reserve margin and high capital costs result in eliminating wind from generation mix.
- Base PVRR includes emissions allowances costs through study period.

# Conclusions from scenario analysis are consistent with recent EEI report

- For regions with high proportions of coal generation, EPA regulations will likely result in significant deterioration in regional reliability and reserve margins

- Investments for $SO_2$, $NO_x$, & HAPs controls may ultimately become obsolete due to aggressive $CO_2$ requirements

- Use of natural gas will increase as CCCTs replace rapid unit retirements; later retirements offer a better chance of replacement with a more balanced energy portfolio

# Perspectives on interstate gas pipeline capacity

- In November 2009, the Rockies Express Pipeline (REX) announced service to the Clarington Hub in eastern Ohio.
- CERA has estimated that REX will displace gas flowing from the Gulf Coast to the Northeast by up to 1.8 billion cubic feet (Bcf) per day. According to the EIA, the three largest pipelines delivering into the Northeast have a combined capacity of 22.5 Bcf per day.
- Additional gas supply from REX is expected to increase gas-on-gas competition in the Southeast and intensify downward pressure on the Henry Hub gas price. However, this impact will be less noticeable under current market conditions with soft Henry Hub gas prices. Furthermore, the effects on gas prices and flows will be temporary and are expected to unwind as REX is extended further eastward.

LG&E KU

# New and Proposed Federal EPA Regulations Will Increase the Cost of Coal-fired Electricity

October 14, 2010

# Environmental compliance is a high priority for E.ON U.S.

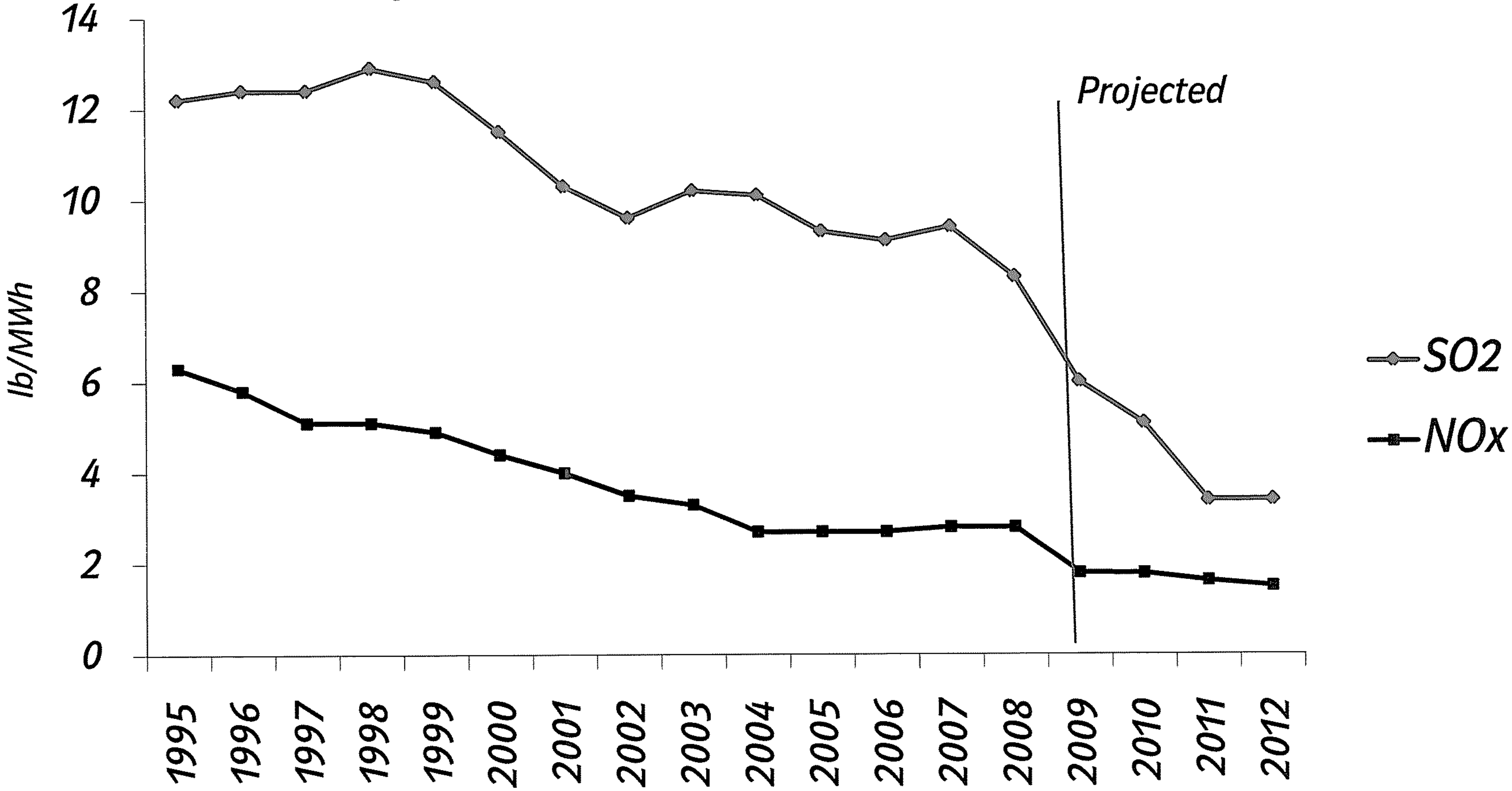
•In the 1970's, we pioneered flue gas desulfurization (FGD) or "scrubber" technology used to control $SO_2$.

•LG&E and KU and their customers have spent $2.6 billion on emission controls since the 1970's.

•Our new Trimble County 2 generating unit will be among the cleanest coal-fired power plants in the U.S., as evidenced by the receipt of the advance coal technology tax incentive for efficiency and environmental controls. Control Technology installed on TC2 includes the following:

- Selective Catalytic Reduction (SCR)
- Dry Electrostatic Precipitator (ESP)
- Powdered Activated Carbon Injection
- Fabric Filter Baghouse
- Wet Flue Gas Desulfurization (WFGD)
- Wet Electrostatic Precipitator (WESP)

# Since 1995, LG&E/KU coal $SO_2$ emission rates have been reduced by 50%; $NO_x$ emission rates by 70%. Further reductions are expected as TC2 and Brown FGD are online.



# Unprecedented number of proposed regulations

EPA is proposing an unprecedented number of regulations that will have a major impact on coal-fired utilities and their customers. The significant risks are as follows –

- Absence of a comprehensive and coordinated federal strategy compels implementation on a piecemeal basis.
- Reversal of prior regulatory determinations will generate large economic impacts.
- Inconsistent deadlines will cause unnecessary compliance costs.
- Short deadlines are compromising state and utility efforts to prepare proper implementation plans.
- Practical implication: We will be proposing construction projects without benefit of final regulations in order to meet federal deadlines for compliance because of long lead time in fabrication and construction.

# *New air regulations*

- *National Ambient Air Quality Standards* **(NAAQS)** *– lowers the $SO_2$, $NO_2$, ozone, and Particulate Matter (PM) standards which will make Louisville a "nonattainment" area subject to federal sanctions.*

- *Clean Air Transport Rule* **(CATR)** *– aimed at reducing air quality problems ($SO_2$, $NO_x$, ozone and PM) in the eastern U.S.*

- *Maximum Achievable Control Technology* **(MACT)** *for Hazardous Air Pollutants* **(HAP)** *– new federal focus on plant by plant controls (as opposed to a system basis) will dramatically increase the cost of reducing mercury and HAP other emissions.*

- *Carbon Dioxide* **($CO_2$)** *Best Available Control Technology* **(BACT)** *– EPA will require implementation of BACT despite the consensus that no commercial scale control technology is currently available.*

# *New coal combustion products and water regulations*

- *Coal Combustion Residuals* **(CCR)** – *(Ash ponds and landfills) – Despite past EPA determinations that CCPs do not pose any significant human health or environmental risks, EPA is considering designation of CCPs as a "hazardous waste" subject to extensive requirements or modifying current "non-hazardous" rules with more stringent requirements. Both approaches will increase costs.*

- *Water quality – EPA is revising cooling water withdrawal and water discharge guidelines and standards.*

# The new EPA regulations will significantly impact Kentucky's electric customers

- *The new regulations are focused on coal-fired power plants.*
- *95% of Kentucky's electricity is provided by coal.*
- *LG&E/KU will comply with any new EPA regulations in the most cost effective manner possible, but the cost increase will be significant.*

# *Short compliance timelines likely once final rules are issued*

- *National Ambient Air Quality Standards* **(NAAQS)** *for $NO_2$ and $SO_2$ – Issued: February - June 2010; Compliance: 2016, 2017 respectively*
- *Clean Air Transport Rule* **(CATR)** *– Projected Final Rule: June 2011; Compliance: January 2012 & January 2014*
- *Maximum Achievable Control Technology* **(MACT)** *for Hazardous Air Pollutants (HAP) – Projected Final Rule: November 2011; Compliance: January 2015*
- *Carbon Dioxide* **($CO_2$ )** *Best Available Control Technology* **(BACT)** *– Issued: May 2010; Compliance: January 2011*
- *Coal Combustion Residuals* **(CCR)** *– Alternatives Proposed: May 2010; Projected Final Rule: uncertain; Compliance: within 5 years of final rule*
- *Water quality – Water withdrawal Projected Issue date: December 2010; Water Discharge Projected Issue date: 2012; Compliance: Uncertain*

# LG&E/KU's coal fleet already has a high level of control technologies, but some additions or enhancements will be required

| | | | | SO2 | | | NOx | | |
|---|---|---|---|---|---|---|---|---|---|
| | Commercial Dates | Net Summer Capacity (MW) | Cooling Towers | FGD Install | Emission Rate (lb/MMBtu) | Emission Control Efficiency | SCR Install | Emission Rate (lb/MMBtu) | Emission Control Efficiency |
| Brown | 1957 - 1971 | 684 | Yes | 2010 (3 units) | 0.12 | 98% | 2012 (1 Unit) | 0.38 | 90% |
| Ghent | 1974 – 1984 | 1,918 | Yes | 2000 – 2009 (4 units) | 0.17 | 94 – 98% | 2003 – 2004 (3 Units) | 0.12 | 80 - 90% |
| Green River | 1954 – 1959 | 163 | No | None | 2.99 | None | None | 0.40 | None |
| Tyrone | 1953 | 71 | No | None | 1.33 | None | None | 0.50 | None |
| Cane Run | 1962 – 1969 | 563 | No | 1976 – 1978 (3 units) | 0.59 | 90 % | None | 0.34 | None |
| Mill Creek | 1972 – 1982 | 1,472 | Yes | 1978 – 1982 (4 Units) | 0.49 | 90 – 92% | 2003 (2 Units) | 0.16 | 85 - 87% |
| Trimble County 1 | 1990 | 383 | Yes | 1990 | 0.12 | 98 % | 2002 | 0.06 | 80 - 85% |
| Trimble County 2 | 2010 | 549 | Yes | 2010 | 0.10 | 98 % | 2010 | 0.04 | 90% |

- All units have precipitators
- Mill Creek 1 does not have a cooling tower.
- Trimble 1 and 2 capacities reflects 75% ownership

LG&E KU

# Technology options for addressing air emissions are known – except for $CO_2$

| Technology | Targeted Pollutant | Regulation Addressed | Removal Rate | LG&E/KU Estimated Cost ($/kW) | LG&E/KU Estimated Cost ($/quantity captured) |
|---|---|---|---|---|---|
| Flue Gas Desulfurization (FGD) | $SO_2$ | CATR, NAAQS | 98% | $450 – 900 | $5,000 – 11,000 /ton |
| Selective Catalytic Reduction (SCR) | $NO_x$ | CATR, NAAQS | 90% | $300 – 500 | $4,000 – 8,000 /ton |
| FGD + SCR (Hg Co-Benefit) | Hg | MACT for HAP | 60-70% | Co-benefit | Co-benefit |
| Fabric Filter & PAC* Injection (with FGD and SCR) | Hg | MACT for HAP | 25-35% | $200 – 500 | $150,000 – 450,000 /lb |
| Sorbent Injection | $SO_3$, Hg | MACT for HAP | TBD | $15 – 30 | TBD |
| **Replace Coal Plant with Gas Plant** | | | | | |
| Combined Cycle Combustion Turbine | All | All | NA | $950 – 1,250 | NA |

*Powdered Activated Carbon

# Despite low emission levels at most stations, sizable investments will be required to meet new air regulations

| Station | Capacity (Net MW) | Options to Address Regulations | Cost ($M) |
|---|---|---|---|
| Brown | 684 | SCR, Fabric Filter Baghouse, PAC Injection, Lime Injection | $350 – 450 |
| Ghent | 1,918 | SCR, Fabric Filter Baghouse, PAC Injection | $950 – 1,150 |
| Green River | 163 | SCR, Fabric Filter Baghouse, PAC Injection | $150 – 250 |
| Cane Run | 563 | FGD, SCR, Fabric Filter Baghouse, PAC Injection, Lime Injection | $850 – 950 |
| Mill Creek | 1,472 | FGD, SCR, Fabric Filter Baghouse, Electrostatic Precipitator (ESP), PAC Injection, Lime Injection, Ammonia | $1,250 – 1,900 |
| Trimble County | 932 | Fabric Filter Baghouse, PAC Injection | $150 – 200 |
| **Replace Coal Plant with Gas Plant** | | | |
| Potential CCCT Replacement | 640 | 640 MW 2x1 Combined Cycle Combustion Turbine | $600 – 800 |

Note: does not include any investment to control for $CO_2$

# Proposed EPA CCR regulations would require dry storage and closing of existing ash ponds

- Retrofit or close 21 ponds, including 10 ash ponds and 11 process/runoff ponds across the fleet (8 stations)
- Build landfills for future storage (Brown, Cane Run, Ghent, Mill Creek, Trimble County)
- Construct new process water ponds for each operating site
- Closing ponds and moving to dry storage will cost an estimated $700 million over the next ten years under the proposed CCR rules for non-hazardous waste. Additional closure costs will be incurred upon plant retirements.

# Increased water withdrawal and discharge requirements

*Potential federal EPA water regulations would impose more stringent requirements on water withdrawal and discharges*

- *Potential addition of cooling towers or discharge water treatment systems*
  - *Stations without cooling towers: Cane Run, Green River, Mill Creek 1, Tyrone*

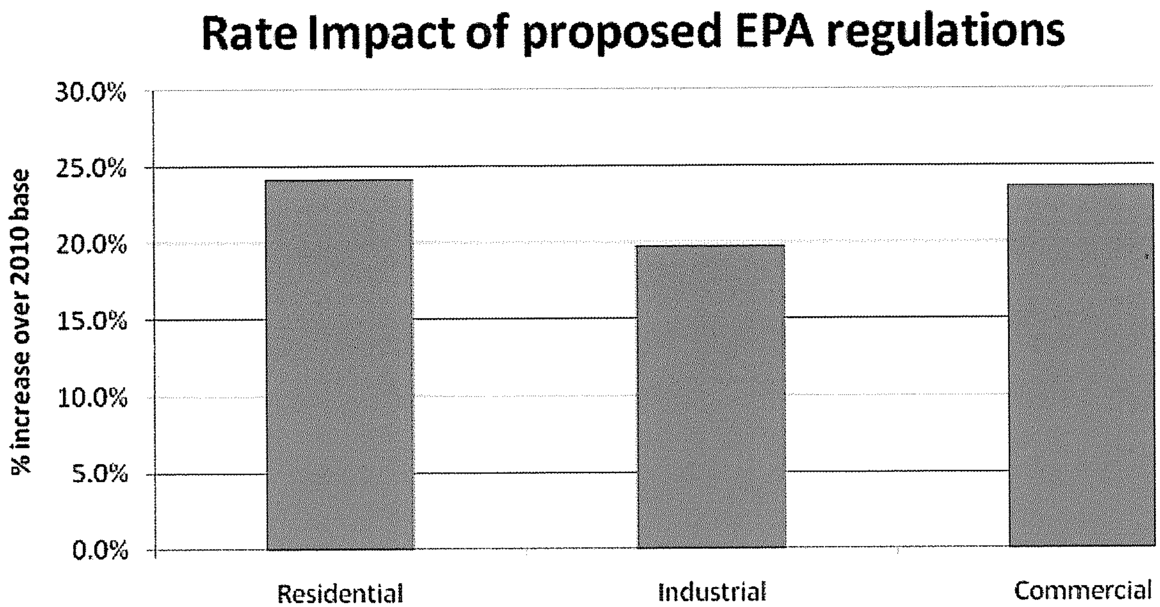
- *New treatment technologies are being developed for water discharges but are not widely deployed in utility operations*
  - *Physical-chemical treatment and/or biological treatment systems may be required*
  - *Cost of $40 - $300 million for each site pending final regulations, specific standards, and treatment volumes*

# Estimate at least $4 billion in capital costs needed over next ten years

| Regulation | Capital ($M) | Annual Operating Expense ($M) |
|---|---|---|
| Air | $3,300 – 5,000 | $150 – 300 |
| CCR | $700 | To be determined |
| Water | To be determined | |

# Cumulative impact of proposed EPA regulations will significantly increase electricity rates

- *Due to these regulations, by 2019 rates could increase by over 20% and almost $550 million annually.*




*Note: This calculation does not include potential compliance costs for water regulations, Renewal Portfolio Standards (RPS) or carbon dioxide (CO2) reductions.*

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# *Challenges and risks related to proposed regulations*

- **Short time horizon** – *some air regulations would require compliance as early as 2012 with the most costly regulations beginning in 2014 and 2015. This allows insufficient time to design facilities, obtain necessary federal and state regulatory approvals, contract with vendors and install equipment.*

- **Potential impacts on system reliability and transmission system** – *one consequence of the proposed regulations will be the retirement of significant amounts of coal-fired generation across the region.*

- **Rapid cost escalation** – *industry rush to achieve compliance will drive up labor and material costs (repeat of 2008) and make it difficult to obtain labor and equipment at any price.*

- **$CO_2$ policy could change** – *uncertainty associated with future $CO_2$ legislation could result in less than optimal long-term investment decisions.*

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# *What should the KPSC expect?*

- *Requests for approval of environmental compliance projects perhaps before the federal regulations are finalized*
- *Compressed construction timelines due to compliance timing*
- *Additional compliance costs to meet implementation dates of federal rules*
- *More frequent requests for rate increases due to substantial upward cost pressures caused by compliance with the federal regulations*

# What is the Company doing?

- Evaluating multiple compliance alternatives
- Participating in industry efforts to advocate more reasonable regulations and timelines
- Communicating our concerns directly with EPA on proposed regulations
- Educating elected officials, regulators and customers on the effect of the federal regulations will have on their electric bill

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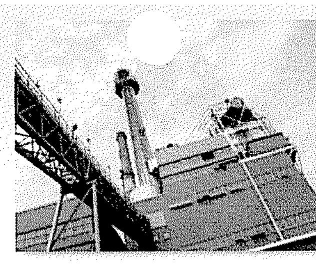
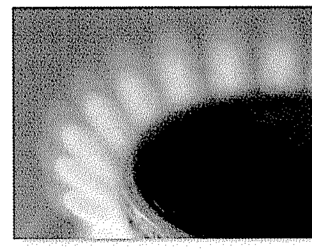
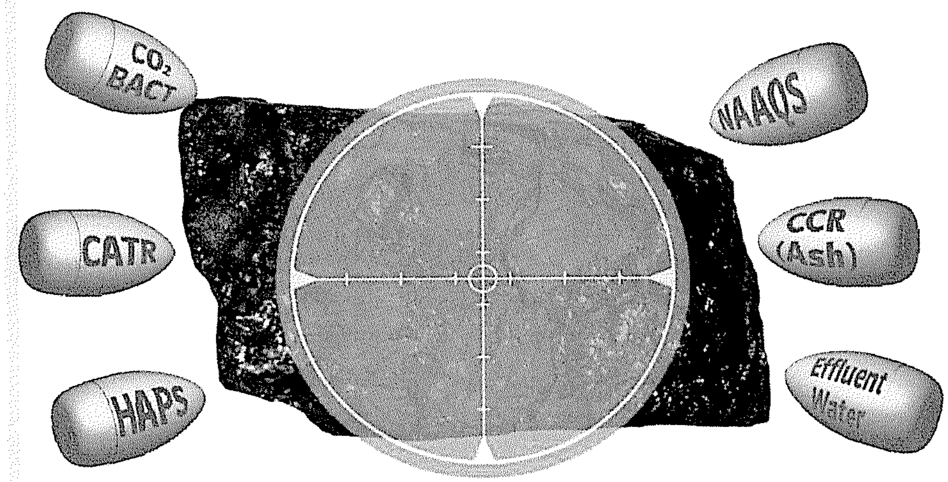
# New and Proposed Federal EPA Regulations Will Increase the Cost of Coal-fired Electricity (Update)

May 31, 2011





# Balancing Competing Interests




- Economic impact of Coal
- KY State Tax Revenues
- Dependable, Reliable, Local Energy Resource
- Low transportation costs

EPA Regulations

Coal Benefits

*Least Cost Obligation*



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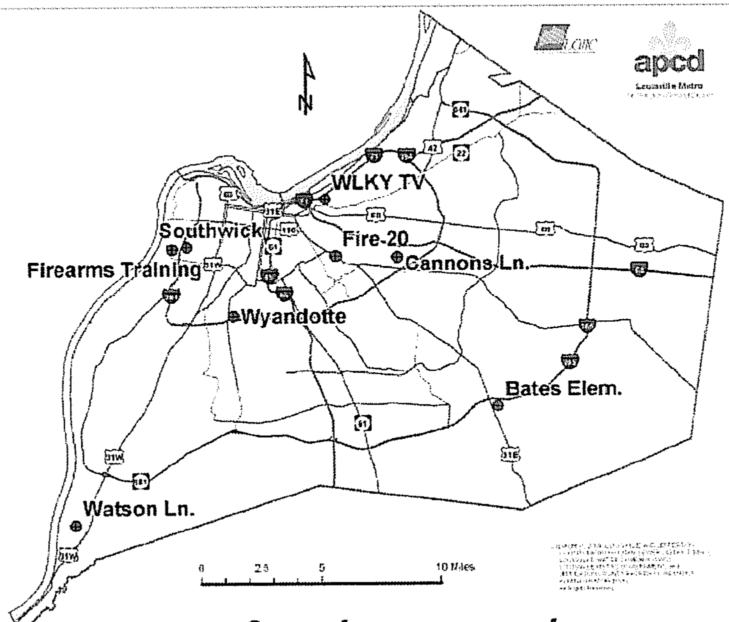
# New air regulations

- *National Ambient Air Quality Standards (**NAAQS**)*
  - — *New 1-hour standard for $SO_2$ and $NO_2$*
  - — *Ground level air monitors across the state*
  - — *Compliance by 2016 or 2017*




- *Monitoring Results in 2010*
  - — *No monitors in Kentucky indicate non-attainment for the new 1-hour $NO_2$ NAAQS.*
  - — *Jefferson Co. monitors indicate non-attainment for the new 75 ppb 1-hour $SO_2$ NAAQS.*
  - — *Mill Creek and Cane Run are the two largest $SO_2$ emission sources in Jefferson Co.*
  - — *Jefferson Co. is required to implement plans to lower $SO_2$ emissions*



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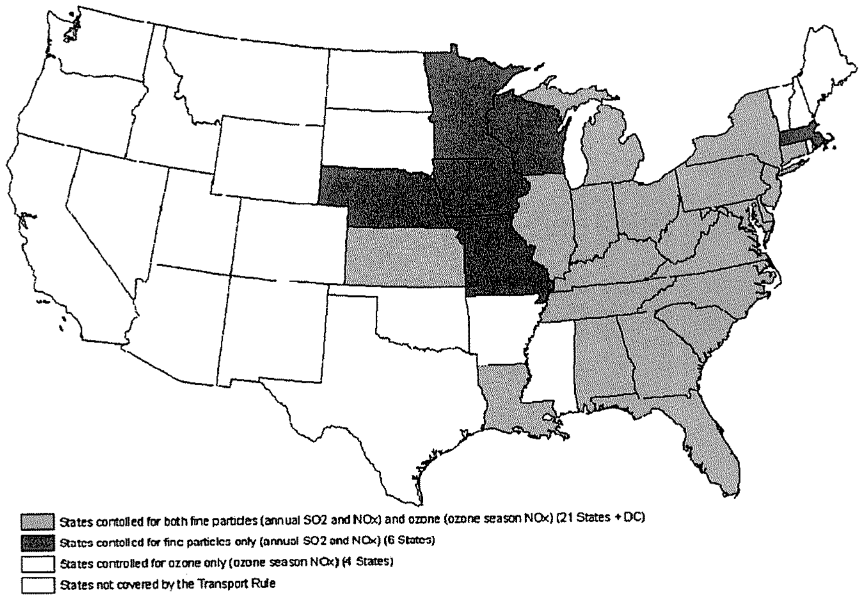
# New air regulations




- *Clean Air Transport Rule (CATR)*
  - *Downwind air pollution effects on $PM_{2.5}$ and ozone*
  - *Regional transport of $SO_2$ and $NO_x$*
  - *Possible compliance dates of 2012 and 2014.*

- *Clean Air Transport Rule Allowance Proposal*
  - *LG&E and KU combined allowances*
    - *Reduce $No_x$ by 15%*
    - *Reduce $SO_2$ by 40%*



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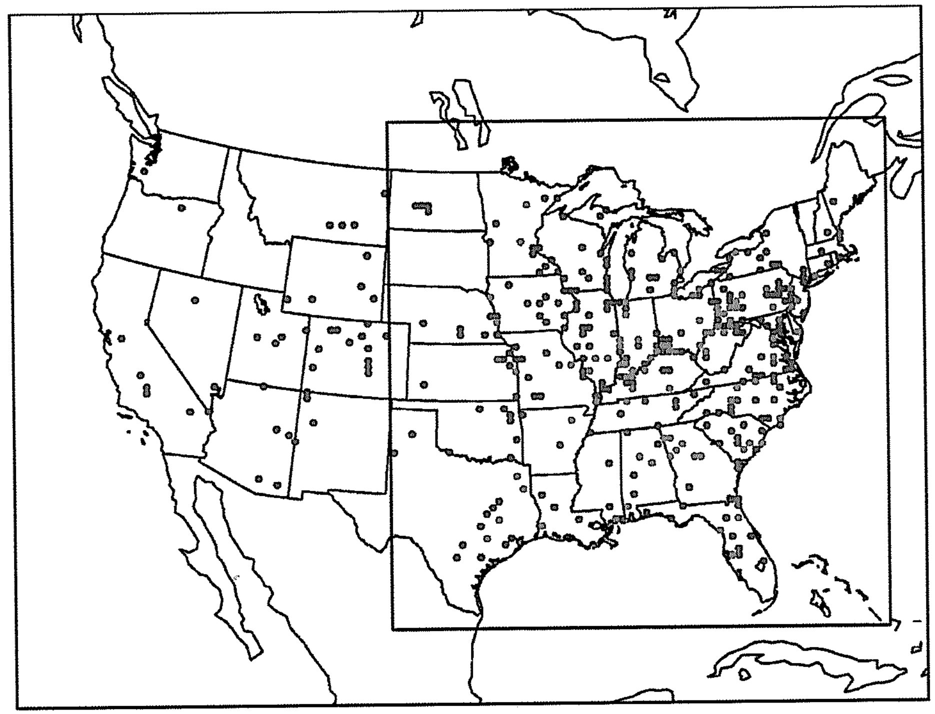
# New air regulations

- *Maximum Achievable Control Technology (MACT) for Hazardous Air Pollutants (HAPs)*
  - *Mercury, Arsenic, Selenium*
  - *Acid aerosols*
  - *Plant-by-plant controls*
  - *Compliance by 2015 or 2016*



## *Update*

- *Draft rule issue March 16, 2011*
- *60 Day comment period started May 3, 2011*
- *Final rule expected November 2011*



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# New air regulations

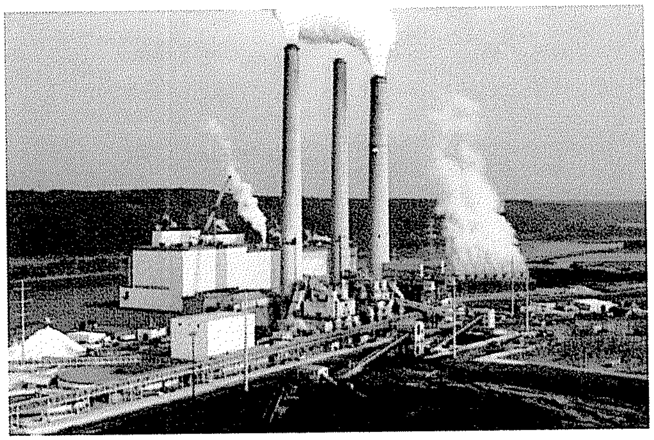
## *Maximum Achievable Control Technology (MACT) Requirements*

| Electric Utility HAP Groups | Regulated Pollutant | Potential Surrogate | Proposed Surrogate Limit* |
|---|---|---|---|
| Non- mercury hazardous metals | As, Be, Cod, Co, Cr, Man, Ni, BP, Sib & Se - individually or total | Total Particulates (filterable PM + condensable** PM) | 0.030 lbs/mmBtu or 0.30 lbs/MWh |
| Mercury | Mercury | none | 1.2 lb/Tbtu or 0.013 lb/GWh |
| Acid gases | Hydrochloric acid (HCl) | Sulfur Dioxide ($SO_2$) | 0.20 lb/mmBtu or 2.0 lbs/MWh |
| Hazardous organics | Numerous organic compounds | N/A | Annual emission test - No limit |
| Dioxin/Furan | Several congeners of both dioxin and furans | N/A | Annual emission test - No limit |

* - Compliance can be based on a plant-wide average over a 12-month period

** - Condensable PM is primarily sulfuric acid mist

# New air regulations



- *$CO_2$ Best Available Control Technology* **(BACT)**
  - *Applies to permits for new or modified sources beginning in 2011*
  - *Greenhouse gas New Source Performance Standard (NSPS); proposal by July 2011*

# LG&E/KU's coal fleet already has a high level of control technologies, but some additions or enhancements will be required

| | | | | SO2 | | | NOx | | |
|---|---|---|---|---|---|---|---|---|---|
| | Commercial Dates | Net Summer Capacity (MW) | Cooling Towers | FGD Install | Emission_Rate (lb/MMBtu) | Emission Control Efficiency | SCR Install | Emission_Rate (lb/MMBtu) | Emission Control Efficiency |
| *Brown* | *1957 - 1971* | *684* | *Yes* | *2010 (3 units)* | *0.12* | *98%* | *2012 (1 Unit)* | *0.38* | *90%* |
| *Ghent* | *1974 – 1984* | *1,918* | *Yes* | *2000 – 2009 (4 units)* | *0.17* | *94 – 98%* | *2003 – 2004 (3 Units)* | *0.12* | *80 - 90%* |
| *Green River* | *1954 – 1959* | *163* | *No* | *None* | *2.99* | *None* | *None* | *0.40* | *None* |
| *Tyrone* | *1953* | *71* | *No* | *None* | *1.33* | *None* | *None* | *0.50* | *None* |
| *Cane Run* | *1962 – 1969* | *563* | *No* | *1976 – 1978 (3 units)* | *0.59* | *90 %* | *None* | *0.34* | *None* |
| *Mill Creek* | *1972 – 1982* | *1,472* | *Yes* | *1978 – 1982 (4 Units)* | *0.49* | *90 – 92%* | *2003 (2 Units)* | *0.16* | *85 - 87%* |
| *Trimble County 1* | *1990* | *383* | *Yes* | *1990* | *0.12* | *98 %* | *2002* | *0.06* | *80 - 85%* |
| *Trimble County 2* | *2010* | *549* | *Yes* | *2010* | *0.10* | *98 %* | *2010* | *0.04* | *90%* |

- *All units have precipitators*
- *Mill Creek 1 does not have a cooling tower.*
- *Trimble 1 and 2 capacities reflects 75% ownership*



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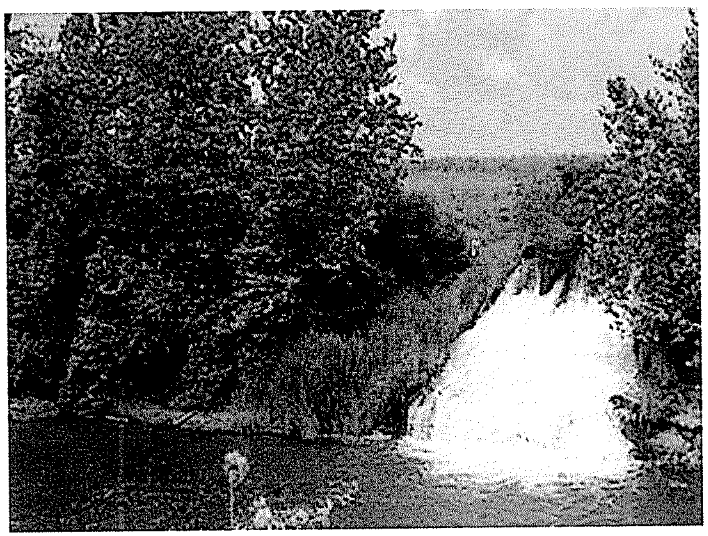
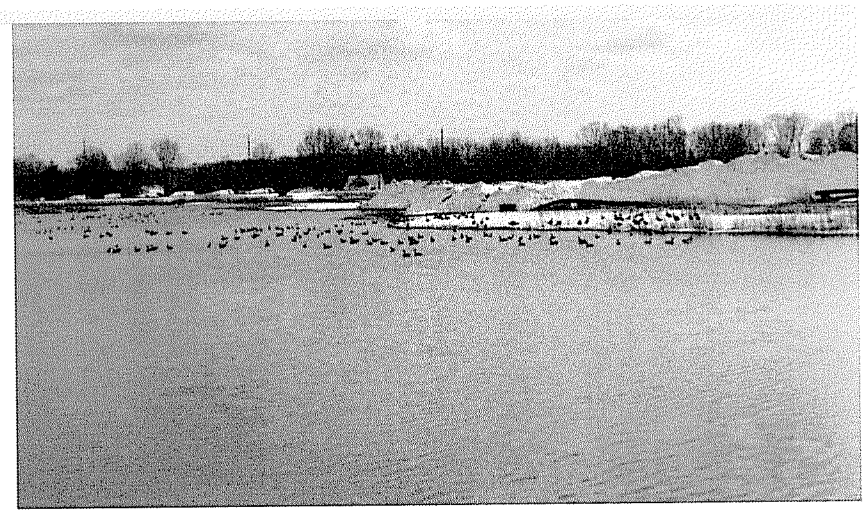
# New coal combustion residuals and water regulations

- *Coal Combustion Residuals (CCR)*
  - *Hazardous or Non-hazardous*
  - *Wet ponds must have liners or convert to dry storage*
  - *Draft rule expected in 2012*
  - *Compliance within 5 years of final rule*





- *Water quality (1974 Clean Water Act)*
  - *Water Withdrawal proposed rule released March 28; expect final rule July 2012*
  - *Water Discharges draft rule expected mid 2012 with final rules by 2013, then compliance*

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# *Proposed EPA CCR regulations would require dry storage and closing of existing ash ponds*

- *Retrofit or close 21 ponds, including 10 ash ponds and 11 process/runoff ponds across the fleet (8 stations)*
- *Build landfills for future storage (Brown, Cane Run, Ghent, Mill Creek, Trimble County)*
- *Construct new process water ponds for each operating site*
- *Closing ponds and moving to dry storage will cost an estimated $700 million over the next ten years under the proposed CCR rules for non-hazardous waste. Additional closure costs will be incurred upon plant retirements.*

# Increased water withdrawal and discharge requirements

*Potential federal EPA water regulations would impose more stringent requirements on water withdrawal and discharges*

- *Cooling towers not mandated; extensive intake studies required that could lead to intake structure modifications*
- *New treatment technologies are being developed for water discharges but are not widely deployed in utility operations*
  - *Physical-chemical treatment and/or biological treatment systems may be required*
  - *Cost of $40 - $300 million for each site pending final regulations, specific standards, and treatment volumes*



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# *Estimate at least $4 billion in capital costs needed over next ten years*

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| *Water* | *To be determined* | |



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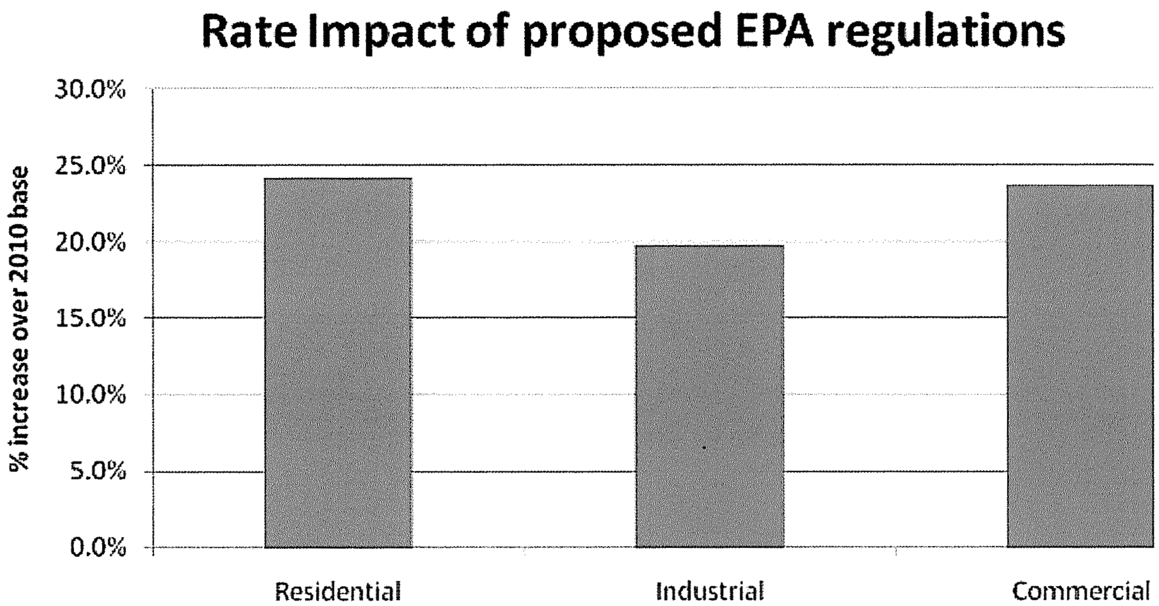
# Cumulative impact of proposed EPA regulations will significantly increase electricity rates

- *Due to these regulations, by 2019 rates could increase by over 20% and almost $550 million annually.*




*Note: This calculation does not include potential compliance costs for water regulations, Renewal Portfolio Standards (RPS) or carbon dioxide (CO2) reductions*



Page 13

# 2010-11 Engineering Assessments

- *Control equipment studies for all stations*
- *Existing Mill Creek scrubber (FGD) Performance Improvement study & structural review*
- *Existing precipitator (ESP) upgrade study*
- *Flow modeling studies for improving unit operation with the SCRs*
- *EW Brown study of a smaller ash pond, with delayed conversion to a landfill.*

# ECR Capital Plan Costs

- *Total company capital costs estimated at $2.5 billion*

  — *KU approximately $1.1 billion*
  — *LG&E approximately $1.4 billion*

- *Projected rate impacts*

  — *KU estimated at 12 % by 2015*
  — *LG&E estimated at 19% by 2015*



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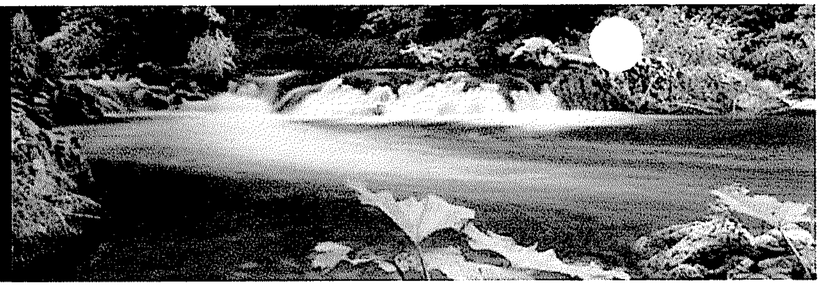
# Risks

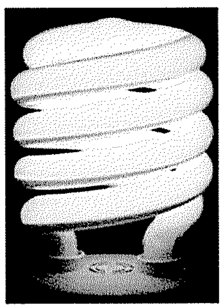
- *Schedule – Completion by 2016*
- *Major equipment lead times*
- *Equipment Availability for fans and electrical motors*
- *Shop Fabrication Space*
- *Engineering and Construction Labor Availability*
- *Cost escalations*

June 4, 2010

# Kentucky's carbon footprint: Where does it lead?

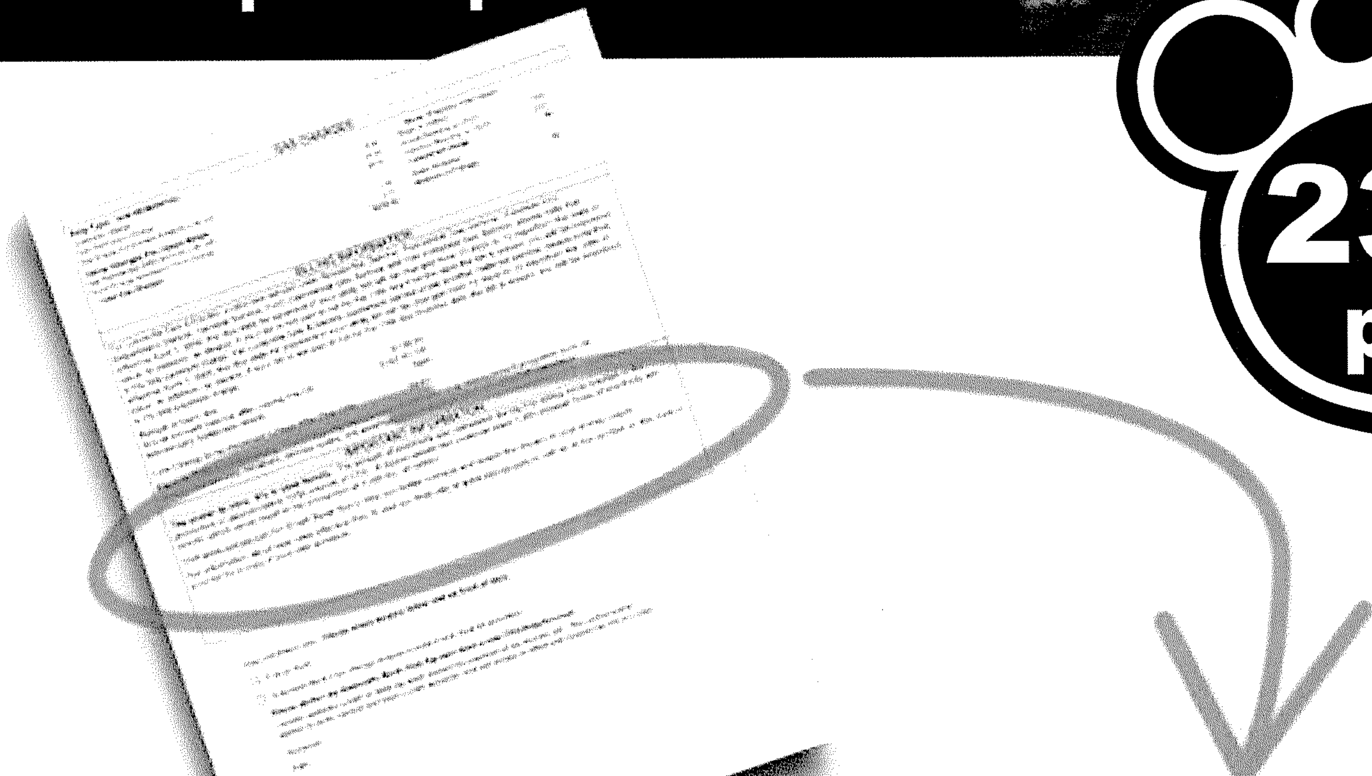
# Tough issues, tough solutions

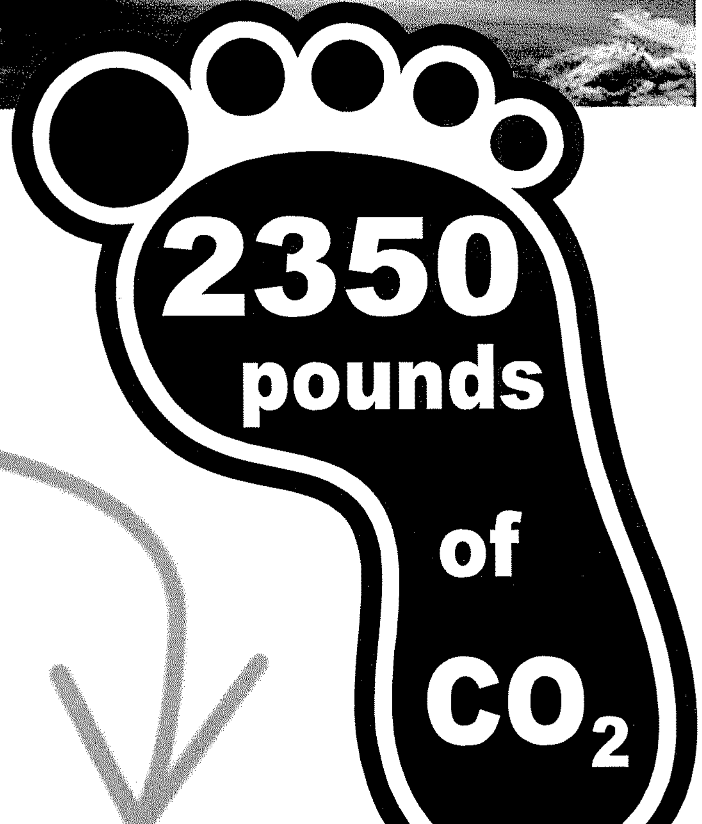




- *Renewable Energy*
- *Transmission Grid*
- *Carbon Legislation or EPA Regulation*
- *Efficient Use of Electricity*

# Carbon footprint is about to leave a deeper impression






**IMPORTANT INFORMATION**

**The power to save. It's in your hands.** The amount of electricity you consumed during this billing cycle resulted in the production of approximately

You can reduce the impact of these emissions by joining our Demand Conservation program, which allows you to help us reduce the need for generating electricity at peak times. Visit our website at www.eon-us.com or call for more information or to sign up today.

To request a copy of your rate schedule, please call (502) 589-1444.

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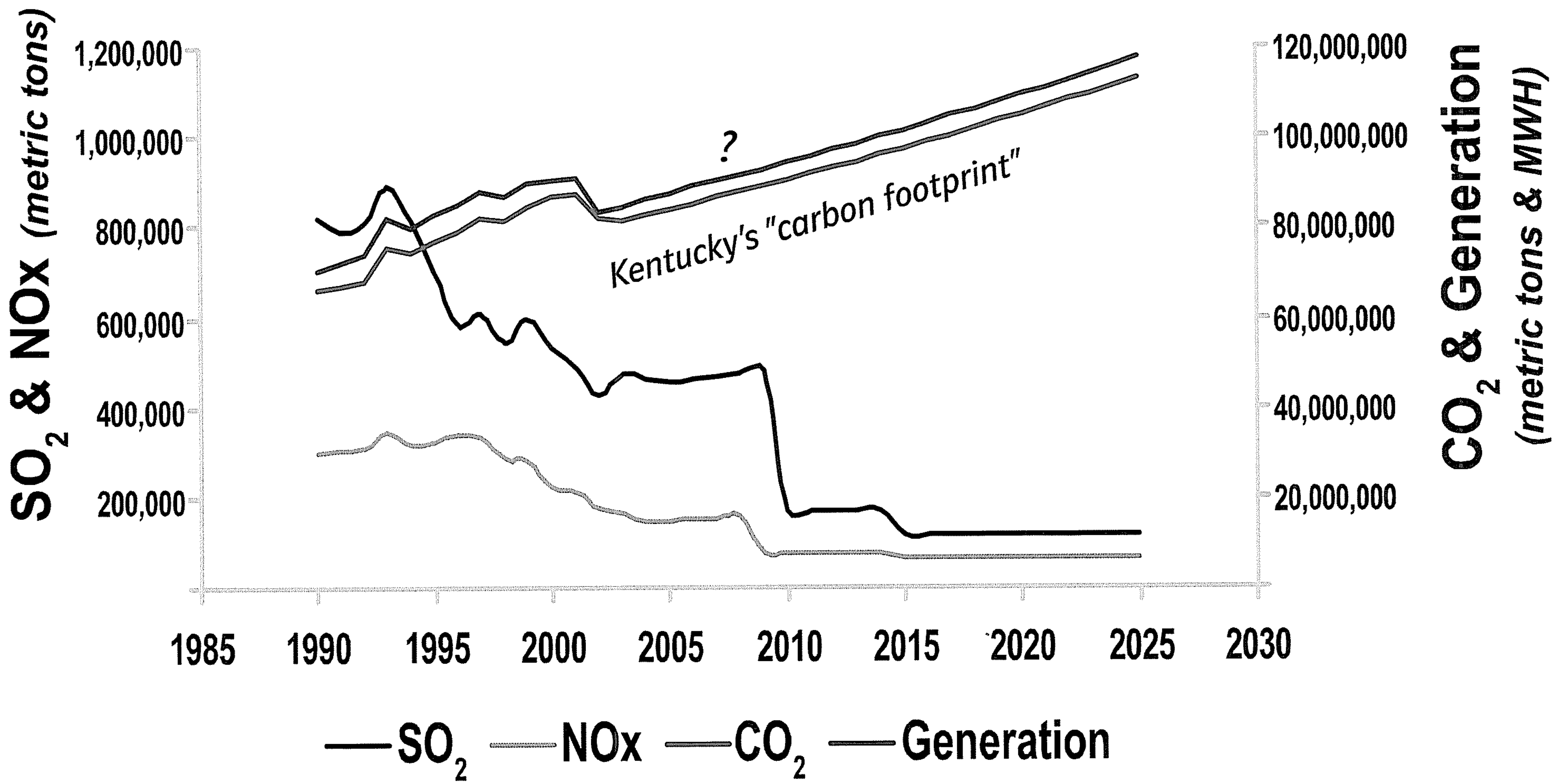
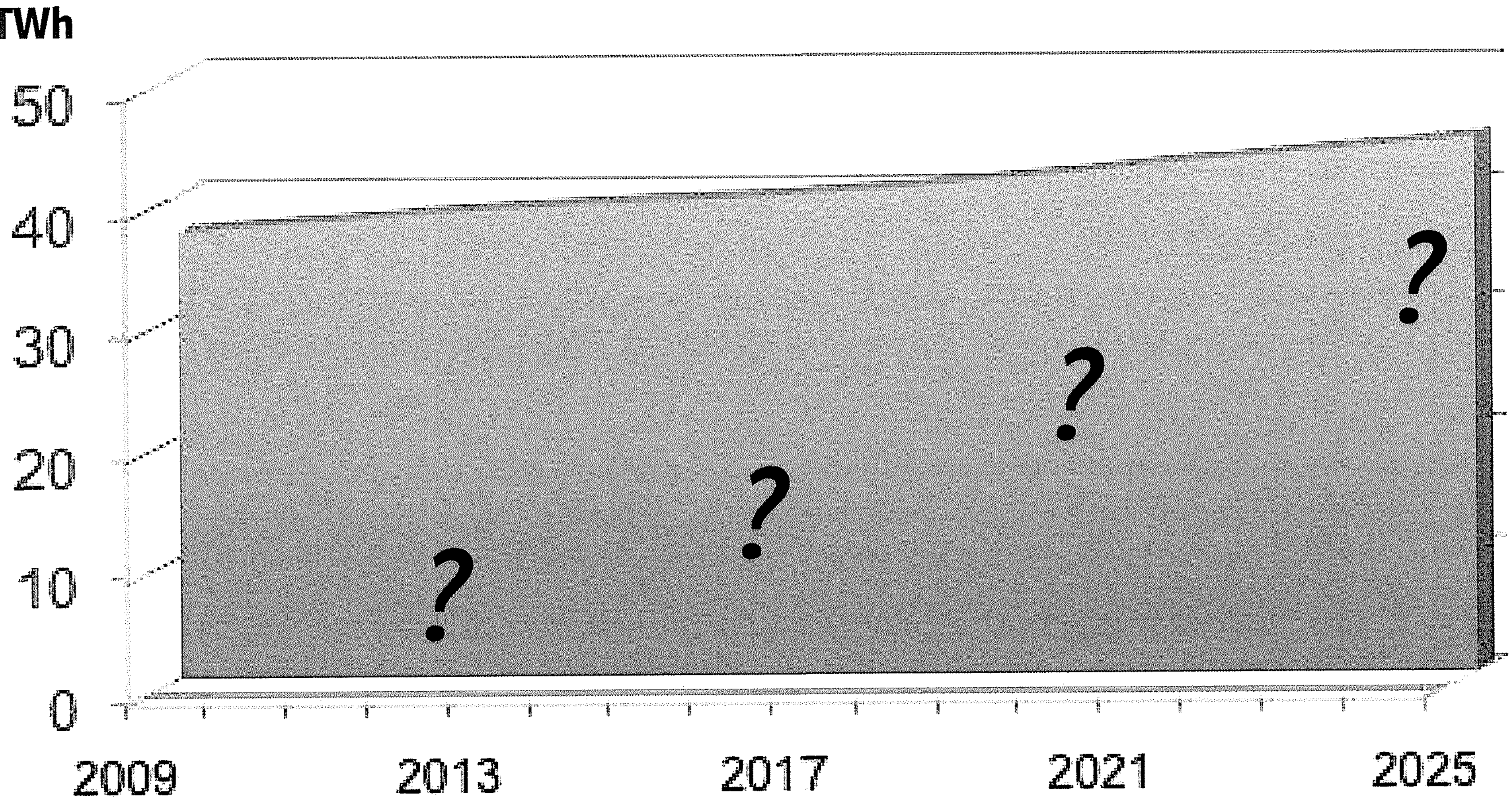
# Past successes, future challenges

## $CO_2$ emissions: **100 times** larger issue than $SO_2$/NOx




*Sources: U.S. DOE Energy Information Administration for historic emissions and generation. U.S. EPA for future $SO_2$ and NOx state budgets. In-house projections of generation and $CO_2$ based on 1.5% annual growth. 2007 data.*

# Your growth in electric usage

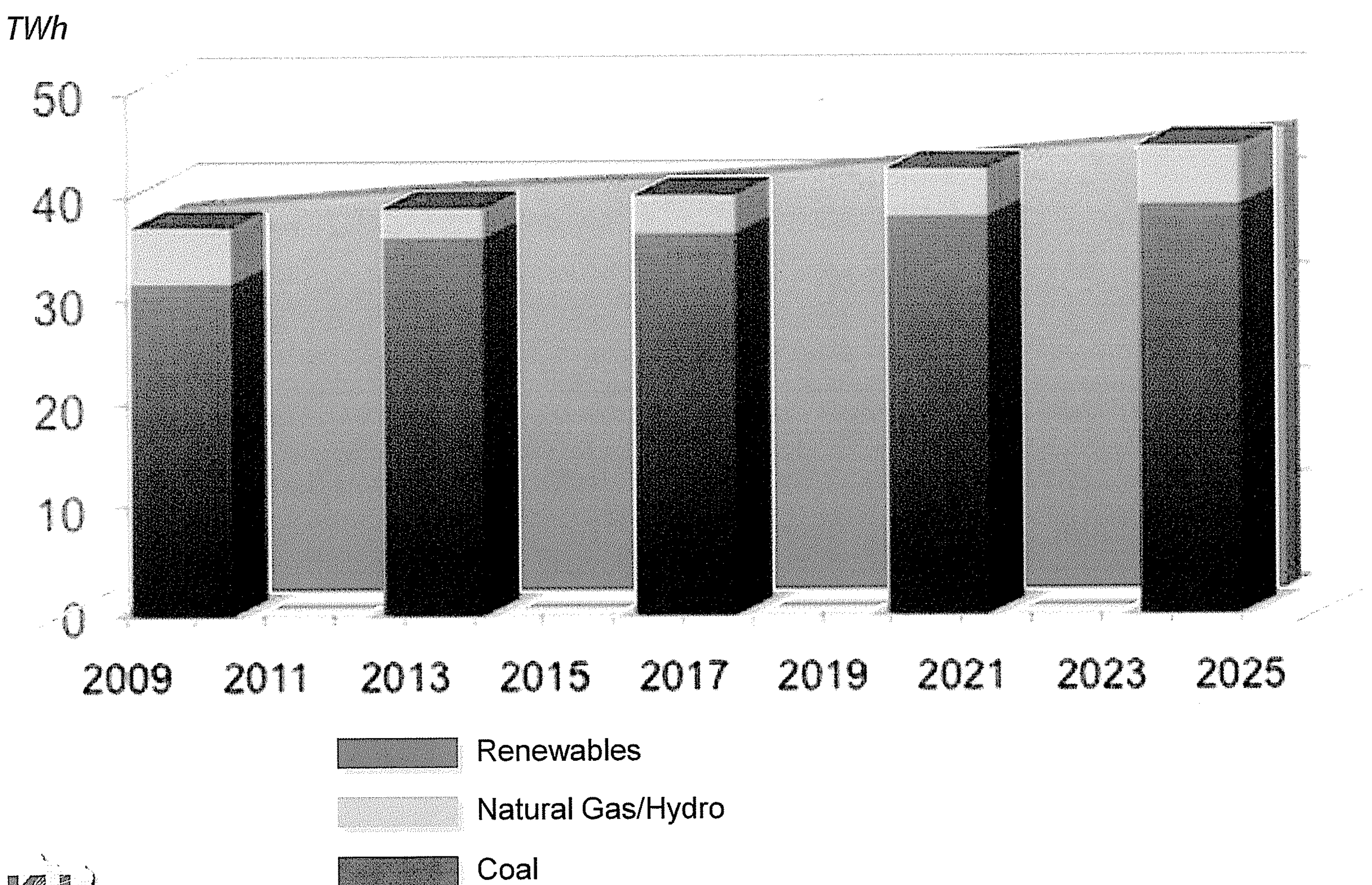




**PROJECTED ELECTRIC DEMAND BY LG&E/KU CUSTOMERS**

*SOURCE: 2008 Integrated Resource Plan*

# How we plan to meet your electric demand

## 95% OF THE ELECTRICITY YOU USE COMES FROM COAL-FIRED POWER PLANTS

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*SOURCE: 2008 Integrated Resource Plan*

# "Renewable portfolio standards"

**Renewable Portfolio Standards (RPS) should be considered in the context of national or regional greenhouse gas restrictions.**

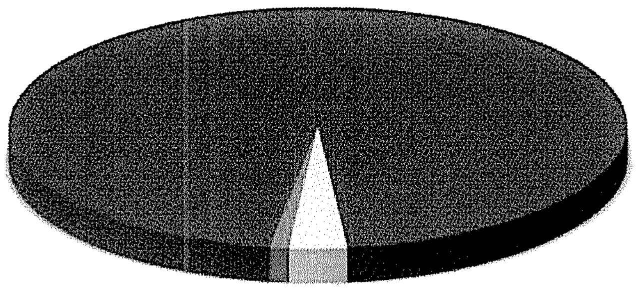
Coal

Natural Gas

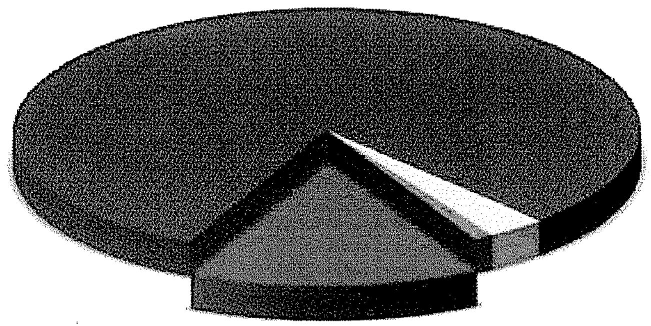
Hydro

Renewables

**Currently Zero Renewables**



**Under 2020 Federal Proposals**



*Note: Existing hydro does not count toward renewable mandates.*

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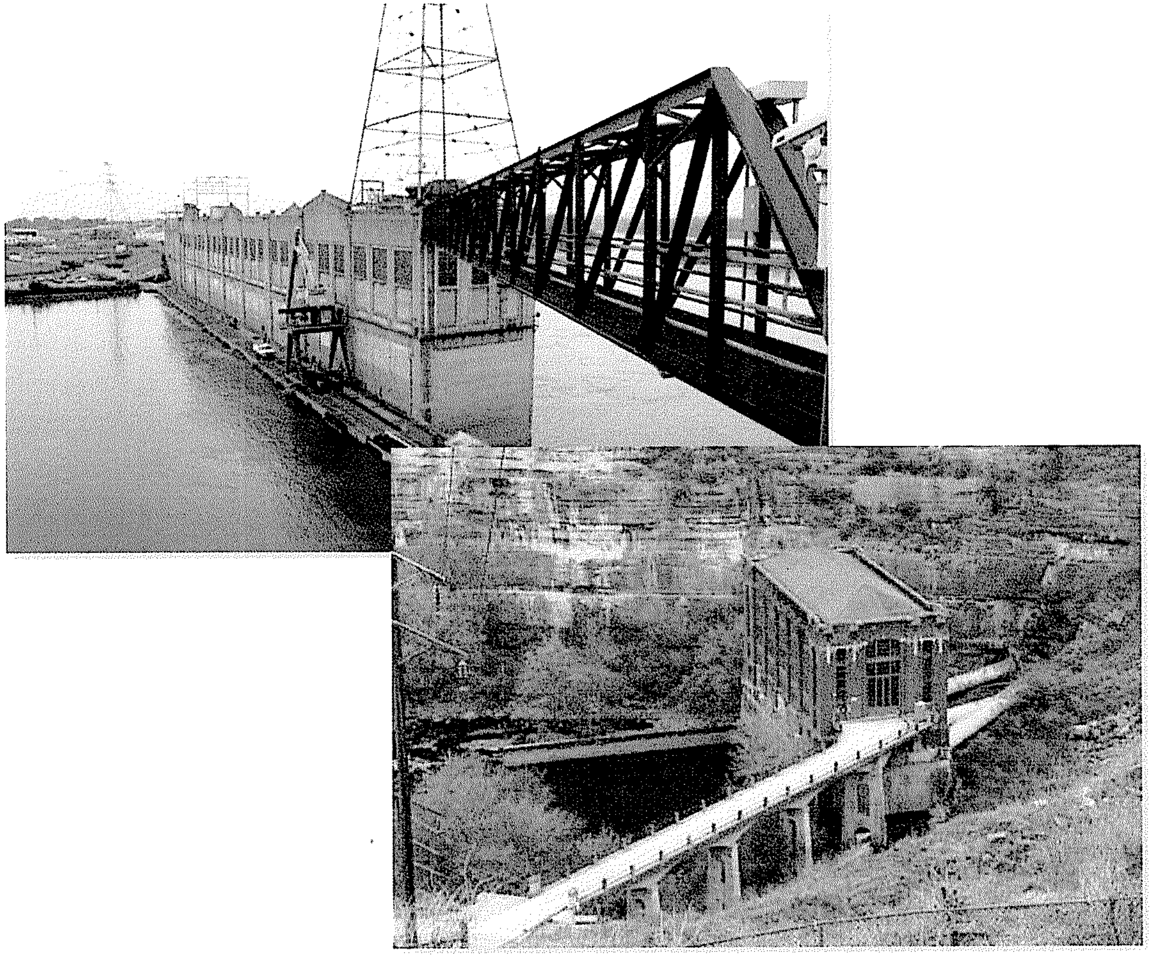
# Considerations — hydro



- *Annual availability equivalent up to 40 percent of continuous maximum capability*
- *Many legal/regulatory entities involved with different missions — recreation, transportation, nature preserves*
- *Low operating cost — "no fuel"*
- *Most hydro locations are already being used*

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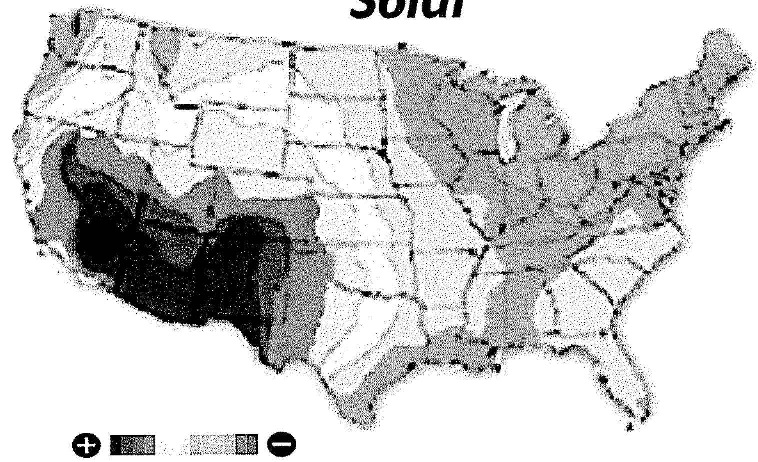
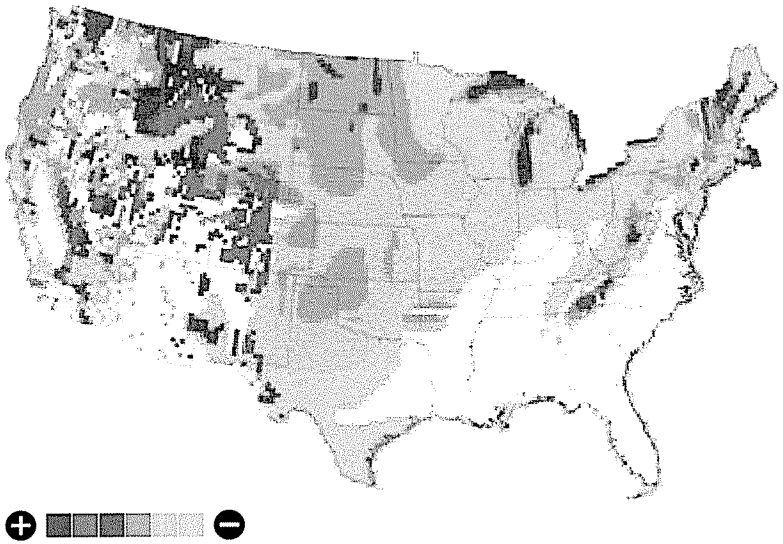
# Considerations — wind, solar and geothermal

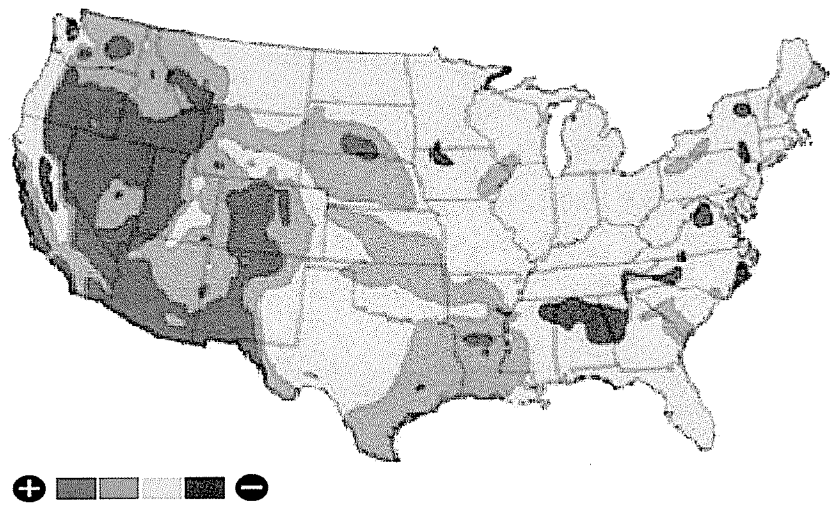
## Solar



## Wind



## Geothermal



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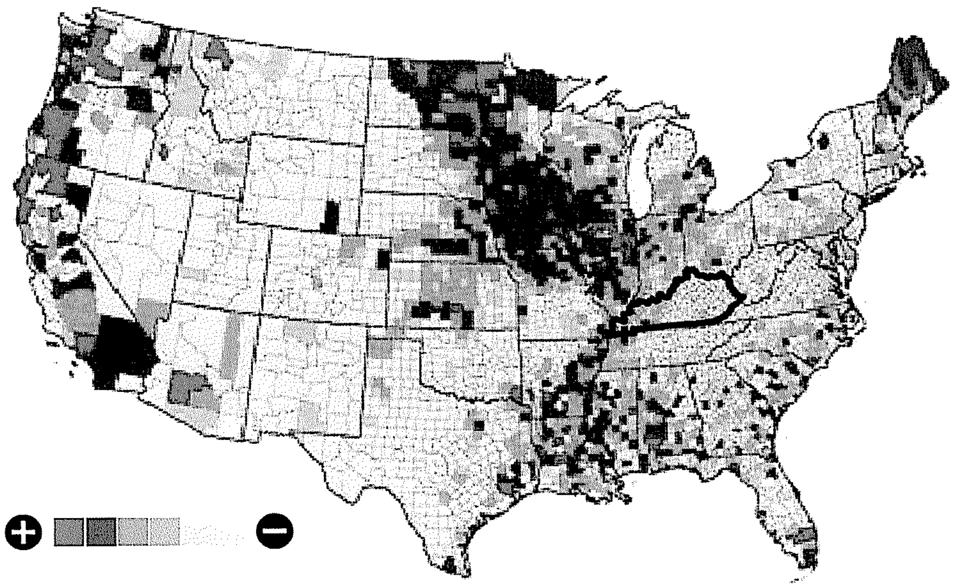
*SOURCES: Dept. of Energy*
*National Renewable Energy Laboratory*

# Considerations — biomass

## *Biomass*

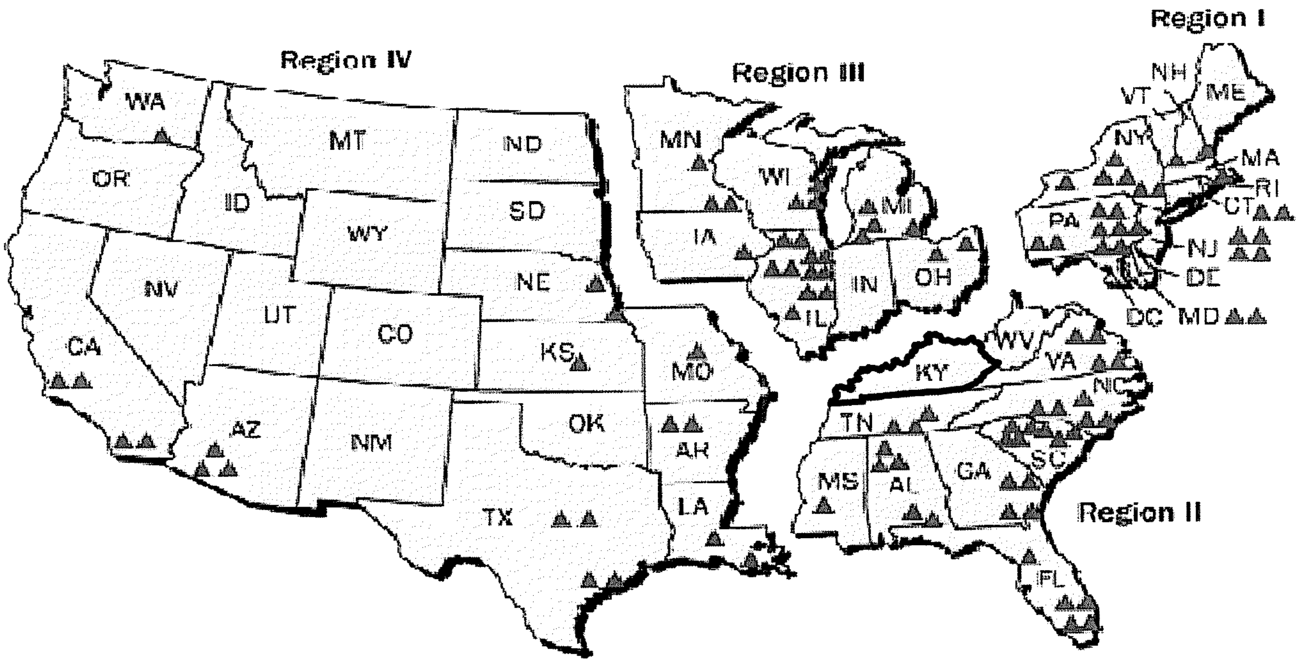


## *Governor's Biomass Task Force*

- *Meet RPS requirements with "in-state" resources*
- *Co-fire biomass with coal*
- *15 million tons of biomass combustion for 12% RPS*
- *Supply infrastructure and sustainability*

*SOURCES: Dept. of Energy*
*National Renewable Energy Laboratory*

# The nuclear option




**Nuclear plants currently licensed to operate**
*SOURCE: Nuclear Regulatory Commission*

- *Zero-carbon option*
- *Enormous investment of time and money*
- *Critical that there be a strong public and political consensus*
- *Disposal still an issue*
- *Nuclear is a* **potential long-term** *solution for Kentucky*

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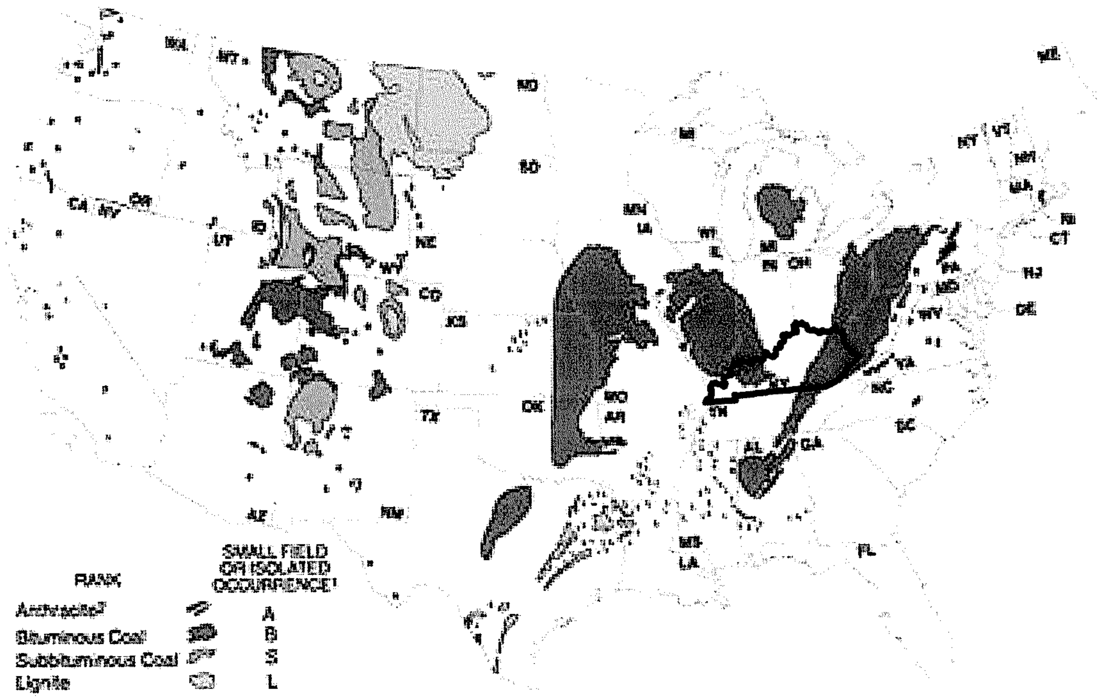
# Considerations — coal




*SOURCE: Dept. of Energy*

- *One of the most widely-used fuels for electrical generation — 90% availability*
- *50% of U.S. power produced today*
- *95% of Ky. power produced today*
- *One of the largest fixed-source producers of $CO_2$*
- *Relatively low transportation costs (river barge)*

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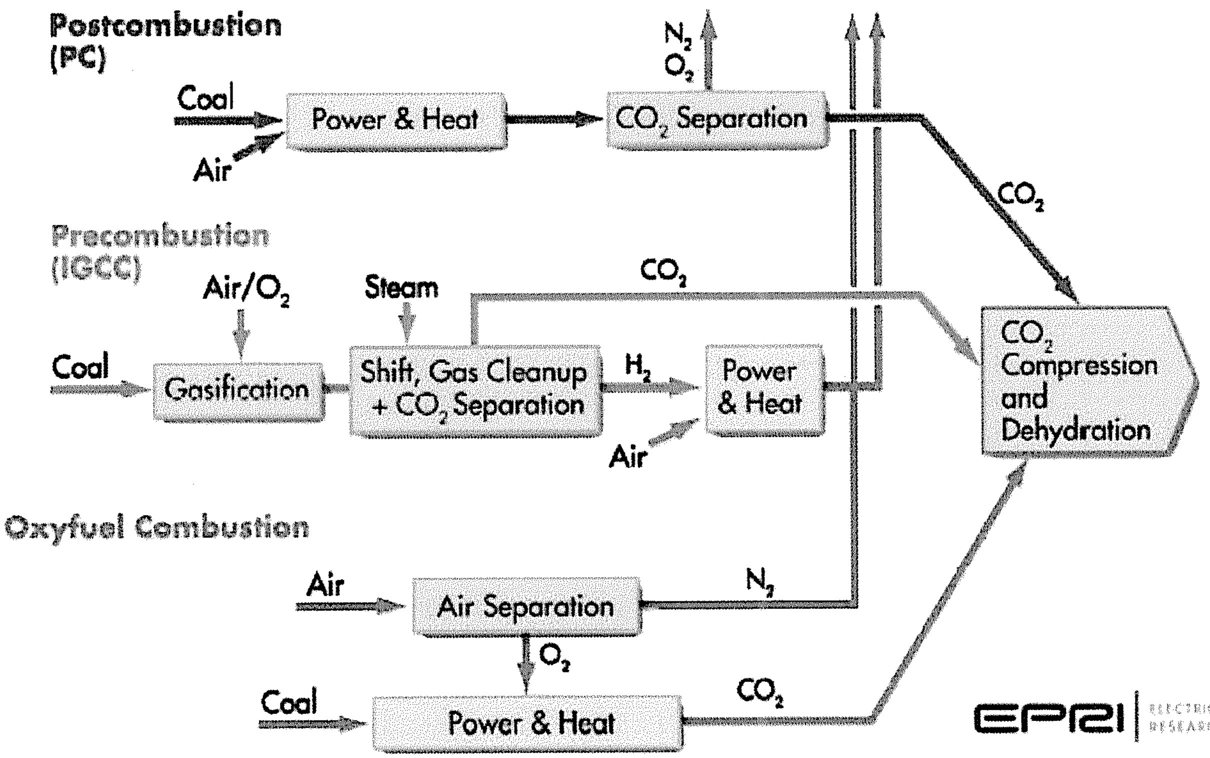
# Carbon capture




EPRI ELECTRIC POWER RESEARCH INSTITUTE

*What's involved….*

- *Three technology paths for capture*
    - *Post-combustion*
    - *Pre-combustion*
    - *Oxy-fuel combustion*
- *Promising options, but no large-scale commercial application yet*
- *E.ON U.S. involved in post- and pre-combustion R&D*

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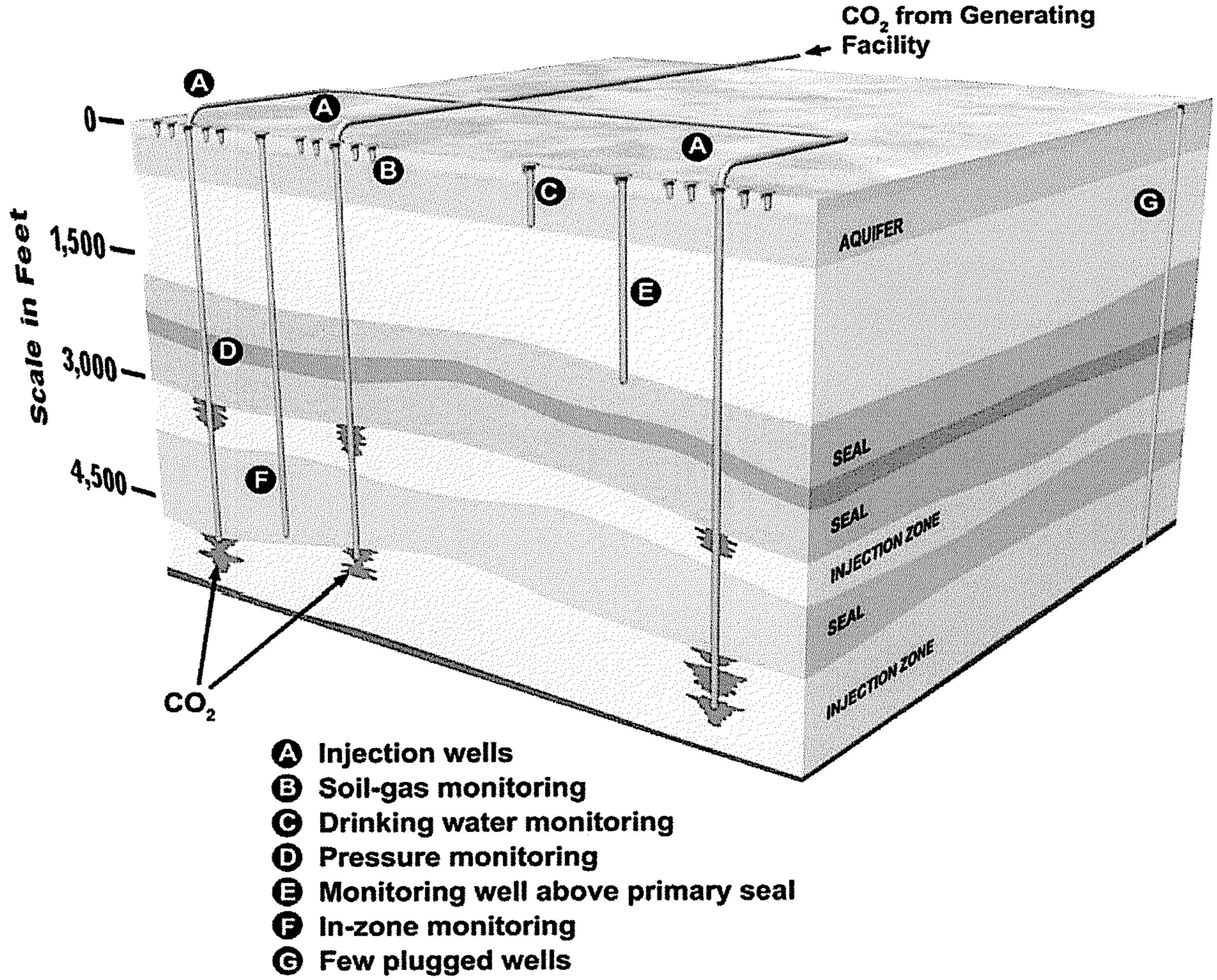
# Carbon capture & sequestration




*What's involved....*

- *"Bury" the problem*
- *Deep underground wells — depleted oil fields*
- *Significant investments in new technology, pumping systems*
- *Promising option, but no large-scale commercial application yet*
- *"NUMBY"*

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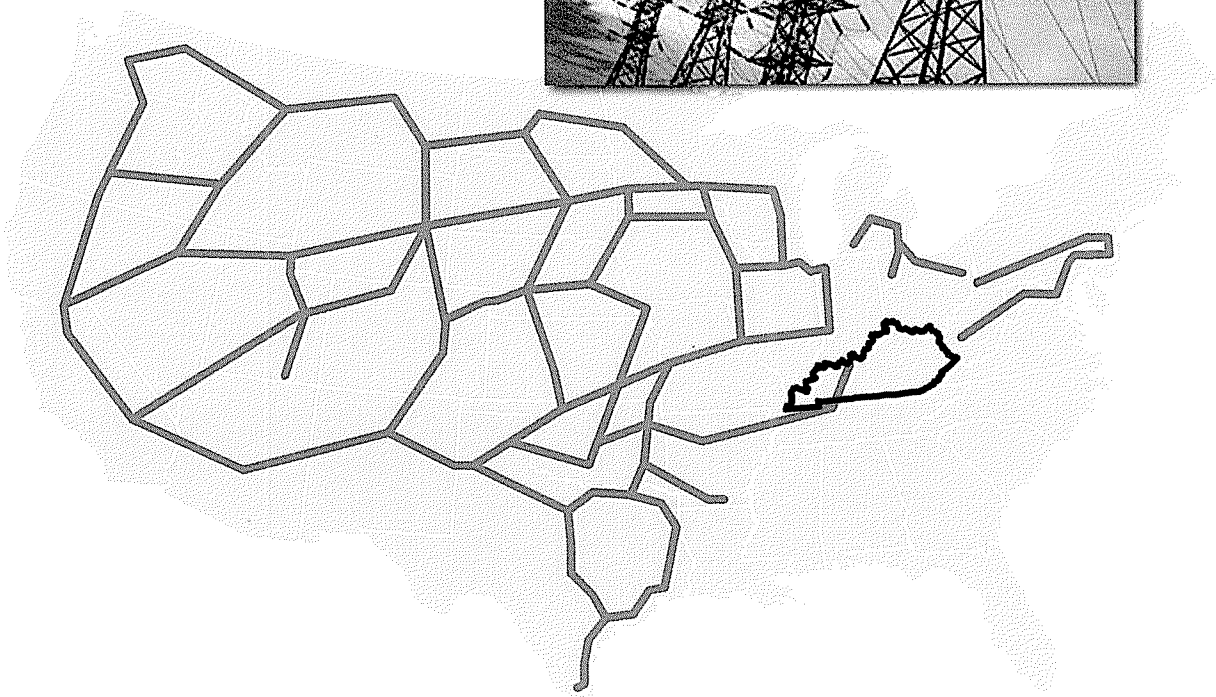
*SOURCE: FutureGen Alliance*

# If we can't make it, why not just *move* it?

*"Costs" of transmission...*

- *Current grid is stretched — would require major new construction at large capital cost*
- *Risks of over-reliance on single highway (Canadian blackout)*
- *Development/approval time*
- *NIMBY*



**Transmission grid system needed to support new renewable power development**

*SOURCE: Dept. of Energy*
*National Renewable Energy Laboratory*

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# Carbon legislation or EPA regulation

*Carefully crafted, comprehensive legislation is a more effective option for controlling greenhouse gas emissions than piece-meal EPA regulation*

## *Legislation should:*

- *Cover economy-wide entities*
- *Provide larger initial allowance allocations and longer phase-out period to ease transition*
- *Begin with an effective safety valve allowance price*

## *EPA regulation via the Clean Air Act would:*

- *Utilize low threshold levels for applicable entities*
- *Establish a significant number of non-attainment areas*
- *Regulate an extremely high-volume pollutant with no commercial control technology available*

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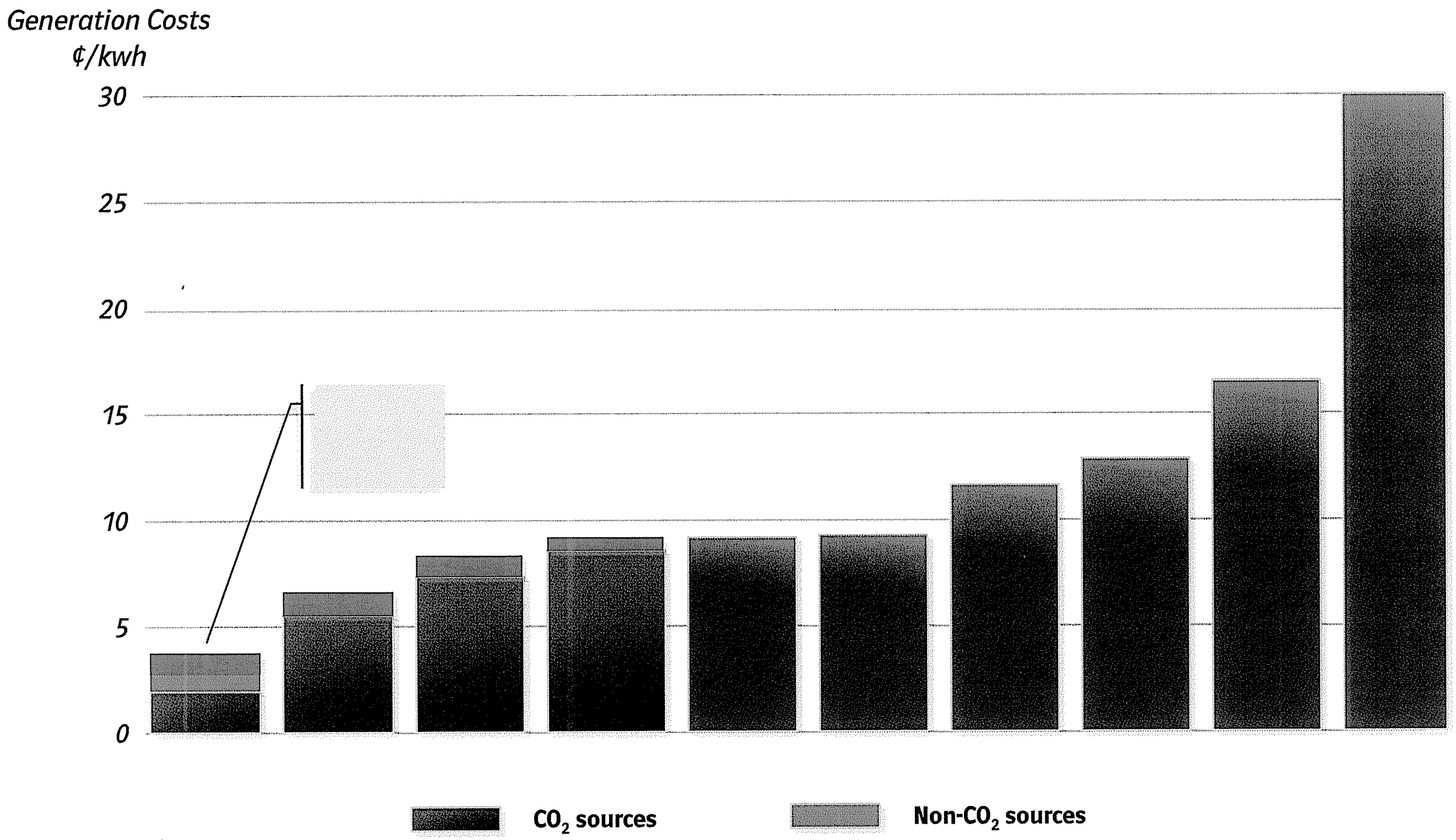
# Cost Comparison

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# American Clean Energy and Security Act of 2009

- *Passed House on June 26, 2009.*
- *Mandates a 17 percent reduction in greenhouse gases by 2020 and 83 percent by 2050 from 2005 levels.*
- *Senate did not advance similar bill.*
- *Current form contains elements that are a step in the right direction.*
- *Copenhagen commitments were based on the House bill targets.*

*To further mitigate costs to our customers, additional elements E.ON U.S. would like to see included in the bill are:*

- *Modified near- and mid-term greenhouse gas reduction targets and timetables.*
- *Inclusion of a price "ceiling" on emission allowance costs.*
- *Extension of the phase-out period for the allocation of allowances.*
- *Preempt inappropriate EPA regulation under the CAA .*

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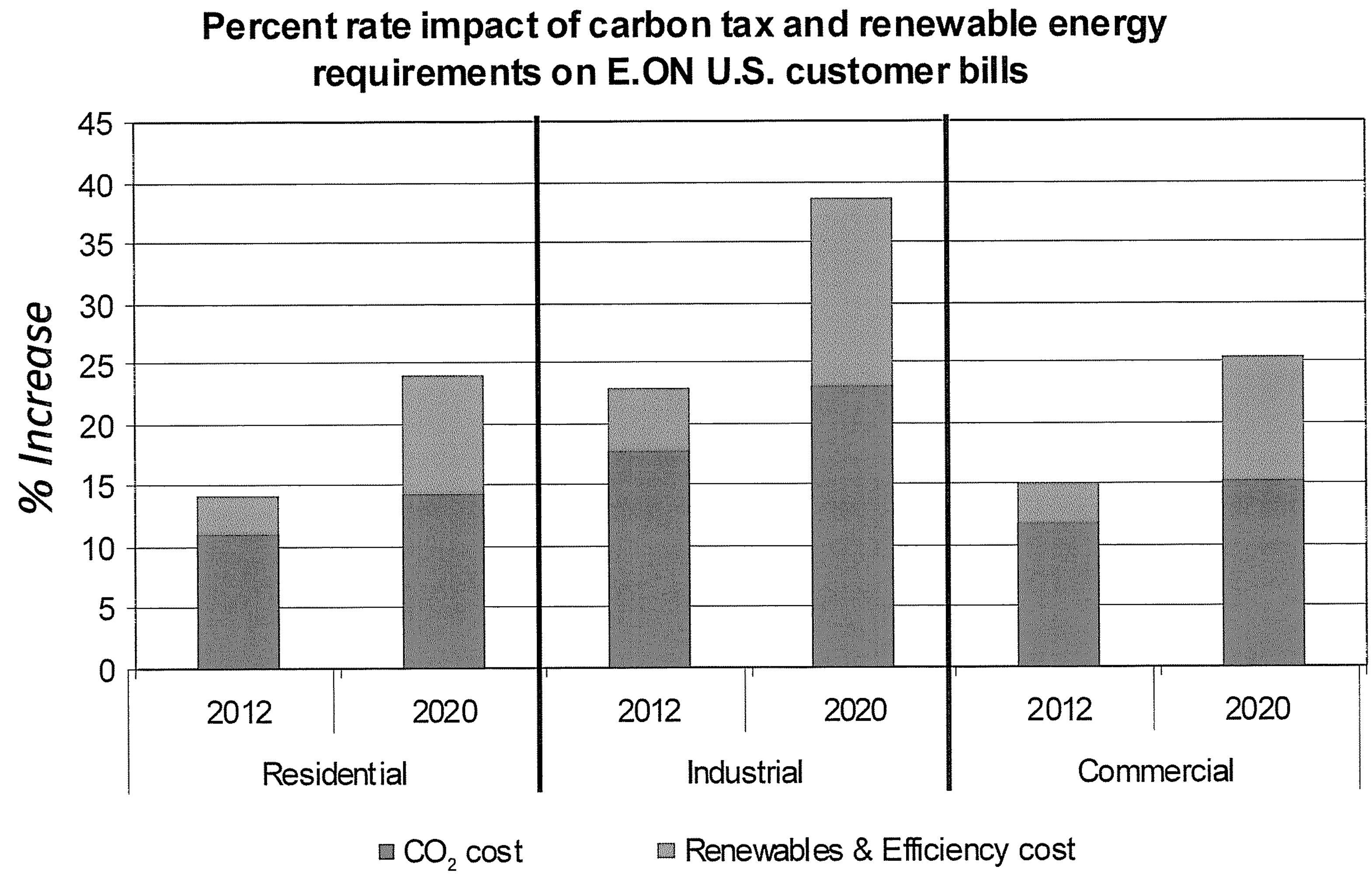
# Estimated costs




- *Percentage increases calculated using 2008 rates applied to 2020 projected sales*
- *CO2 allowance is calculated at $20 a ton, allocation methodology is 41% purchase in 2012, 53% purchase in 2020*
- *Assumes utilities meet the CERES target entirely through purchase of Alternative Compliance Payments (ACPs) set in the bill at 2.5 cents per KWH in 2010 (and subsequently indexed).*

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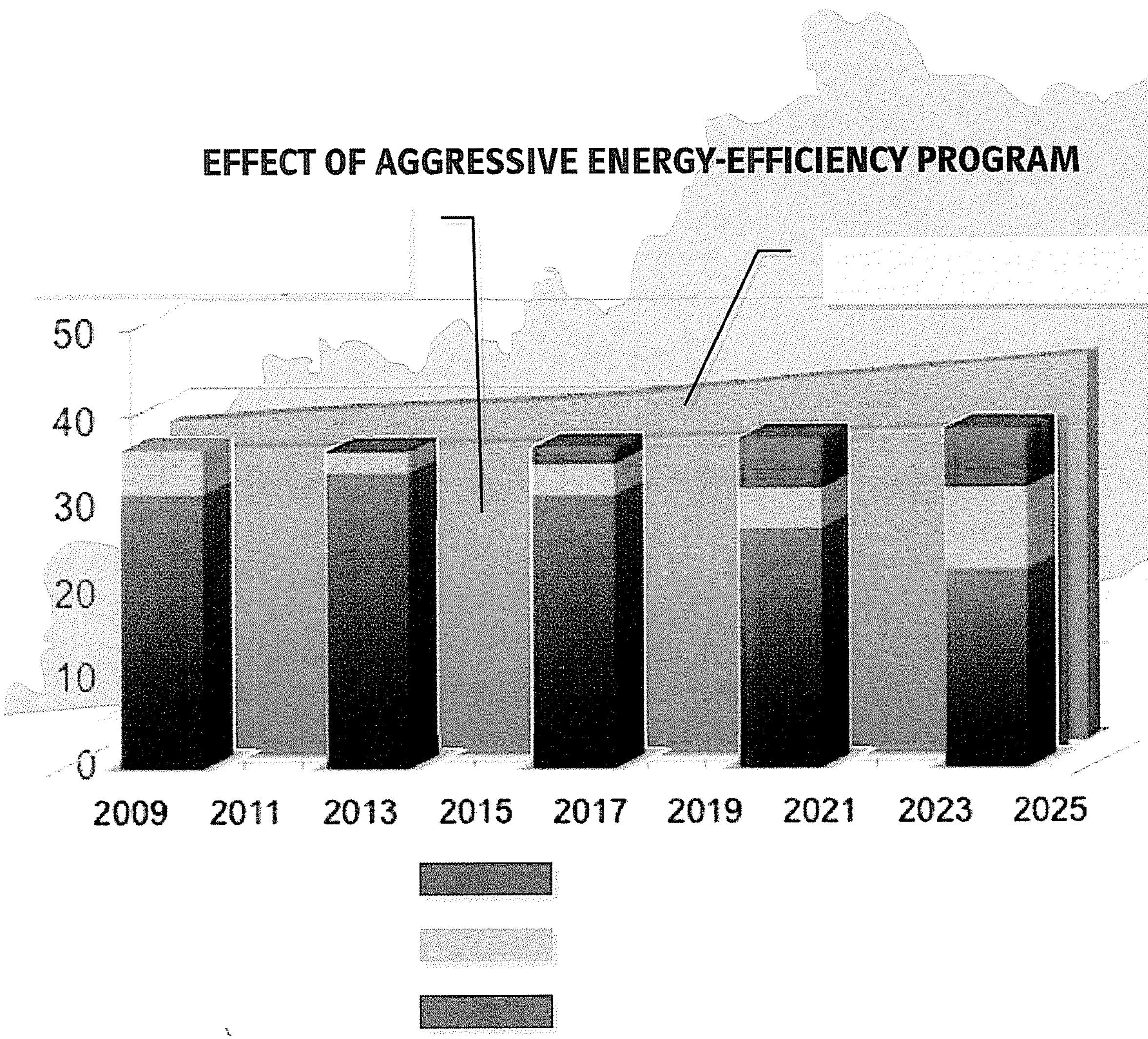
# Reducing demand — the challenge




*What it would take…*

- *15+% reduction in demand*
- *Unprecedented consumer commitment to energy efficiency*
- *Commitment to "smart grid"*
- *Less coal in total generation mix, less exposure to carbon tax, but high cost of purchased or developed renewable power sources*

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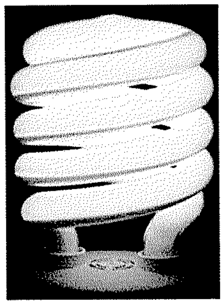
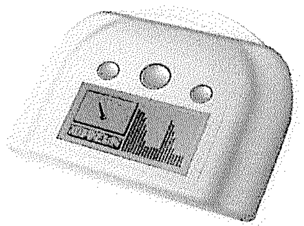
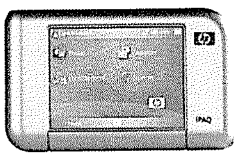
*SOURCE: 2008 Integrated Resource Plan*

# Energy Efficiency Initiatives







- E.ON U.S. is investing more than $25 million in energy efficiency programs annually — at least $182 million over the life of the program

  Examples:
  - Enhanced energy audits
  - Commercial rebates
  - Residential lighting

- Expected to reduce the need for additional generation by more than 500 megawatts

- Conserve Energy During Heavy Demand
  - Load control program: partnership with customers that allows us to cycle off AC units during peak demand
  - Smart meter pilot program: helps customers manage their usage

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# What are "the next steps?"

- *Understand that rising energy costs will be a way of life for years to come — consider everything you do with that in mind*
- *Make major, sustained commitment to energy efficiency*
- *E.ON U.S. — to address issues of carbon capture and sequestration with help of policy-makers*
- *E.ON U.S. — share information and work constructively with policy-makers*


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# Balanced Outcome

- *Insist on a thorough evaluation of cost*
- *Allow technology to catch up*
- *Demand an equitable allocation of carbon credits*
- *Be efficient — seek incentives for efficiencies*


*"To build may have to be the slow and laborious task of years. To destroy can be the thoughtless act of a single day."*

**— Winston Churchill**

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