Volumes 9A - 9B

Duke Energy Kentucky
Case No. 2011-124
Staff First Set Data Requests
Date Received: April 28, 2011

STAFF-DR-01-009

REQUEST:

Provide the Duke Energy and Progress SEC Form 10Ks for the years 2006 through 2009.

RESPONSE:

Please see Attachments Staff DR-01-09 (i)-(viii) for SEC Form 10Ks

PERSON RESPONSIBLE:

James E. Rogers (Duke)

William D. Johnson (Progress)

10kWIZARD
SEC POWER SEARCH

FORM 10-K

Duke Energy Holding Corp. - duk

Filed: March 01, 2007 (period: December 31, 2006)

Annual report which provides a comprehensive overview of the company for the past year

Table of Contents

PART I

PART II

PART III

PART IV

PART IV

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-K

FOR ANNUAL AND TRANSITION REPORTS

PURSUANT TO SECTION 13 OR 15(d) OF THE

SECURITIES EXCHANGE ACT OF 1934

(Mark One)

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2006 or

☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from _________ to _________

Commission file number 1-32853

DUKE ENERGY CORPORATION

(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	20-2777218 (I.R.S. Employer Identification No.)
526 South Church Street, Charlotte, North Carolina (Address of principal executive offices)	28202-1803 (Zip Code)

704-594-6200

(Registrant's telephone number, including area code)

SECURITIES REGISTERED PURSUANT TO SECTION 12(B) OF THE ACT:

Title of each class	Name of each exchange on which registered
Common Stock, without par value	New York Stock Exchange, Inc

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☒ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act. Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports) and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer (as defined in Rule 12b-2 of the Securities Exchange Act of 1934).

Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Securities Exchange Act of 1934). Yes ☐ No ☒

Estimated aggregate market value of the common equity held by nonaffiliates of the registrant at June 30, 2006	$36,684,000,000
Number of shares of Common Stock, $0.001 par value, outstanding at February 23, 2007	1,257,116,278

Table of Contents
TABLE OF CONTENTS

DUKE ENERGY CORPORATION

FORM 10-K FOR THE YEAR ENDED

DECEMBER 31, 2006

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

This document includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Forward-looking statements are based on management's beliefs and assumptions. These forward-looking statements are identified by terms and phrases such as "anticipate," "believe," "intend," "estimate," "expect," "continue," "should," "could," "may," "plan," "project," "predict," "will," "potential," "forecast," and similar expressions. Forward-looking statements involve risks and uncertainties that may cause actual results to be materially different from the results predicted. Factors that could cause actual results to differ materially from those indicated in any forward-looking statement include, but are not limited to:

- State, federal and foreign legislative and regulatory initiatives, including costs of compliance with existing and future environmental requirements;
- Costs and effects of legal and administrative proceedings, settlements, investigations and claims;
- Industrial, commercial and residential growth in Duke Energy's service territories;
- Additional competition in electric markets and continued industry consolidation;
- Political and regulatory uncertainty in other countries in which Duke Energy conducts business;
- The influence of weather and other natural phenomena on Duke Energy operations, including the economic, operational and other effects of hurricanes and ice storms;
- The timing and extent of changes in commodity prices, interest rates and foreign currency exchange rates;
- Unscheduled generation outages, unusual maintenance or repairs and electric transmission system constraints;
- The results of financing efforts, including Duke Energy's ability to obtain financing on favorable terms, which can be affected by various factors, including Duke Energy's credit ratings and general economic conditions;
- Declines in the market prices of equity securities and resultant cash funding requirements for Duke Energy's defined benefit pension plans;
- The level of credit worthiness of counterparties to Duke Energy's transactions;
- Employee workforce factors, including the potential inability to attract and retain key personnel;
- Growth in opportunities for Duke Energy's business units, including the timing and success of efforts to develop domestic and international power and other projects;
- The performance of electric generation and of projects undertaken by Duke Energy's non-regulated businesses;
- The extent of success in connecting and expanding electric markets;
- The effect of accounting pronouncements issued periodically by accounting standard-setting bodies;
- *The ability to successfully complete merger, acquisition or divestiture plans*, including the prices at which Duke Energy is able to sell assets; and regulatory or other limitations imposed as a result of a merger

In light of these risks, uncertainties and assumptions, the events described in the forward-looking statements might not occur or might occur to a different extent or at a different time than Duke Energy has described. Duke Energy undertakes no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

Table of Contents
PART I

Item 1. Business.

GENERAL

Duke Energy Corporation (collectively with its subsidiaries, Duke Energy) is an energy company located in the Americas. Duke Energy provides its services through the business units described below.

In May 2005, Duke Energy and Cinergy Corp. (Cinergy) announced they entered into a definitive merger agreement. Closing of the transaction occurred in the second quarter of 2006. The merger combined the Duke Energy and Cinergy regulated franchises as well as deregulated generation in the Midwest United States.

Duke Energy Holding Corp. (Duke Energy HC) was incorporated in Delaware on May 3, 2005 as Deer Holding Corp., a wholly-owned subsidiary of Duke Energy Corporation (Old Duke Energy). On April 3, 2006, in accordance with their previously announced merger agreement, Old Duke Energy and Cinergy merged into wholly-owned subsidiaries of Duke Energy HC, resulting in Duke Energy HC becoming the parent entity. In connection with the closing of the merger transactions, Duke Energy HC changed its name to Duke Energy Corporation (New Duke Energy or Duke Energy) and Old Duke Energy converted into a limited liability company named Duke Power Company LLC (subsequently renamed Duke Energy Carolinas, LLC (Duke Energy Carolinas) effective October 1, 2006). As a result of the merger transactions, each outstanding share of Cinergy common stock was converted into 1.56 shares of common stock of Duke Energy, which resulted in the issuance of approximately 313 million shares. Additionally, each share of common stock of Old Duke Energy was converted into one share of Duke Energy common stock. Old Duke Energy is the predecessor of Duke Energy for purposes of U.S. securities regulations governing financial statement filing. Therefore, the accompanying Consolidated Financial Statements reflect the results of operations of Old Duke Energy for the three months ended March 31, 2006 and the years ended December 31, 2005 and 2004 and the financial position of Old Duke Energy as of December 31, 2005. New Duke Energy had separate operations for the period beginning with the effective date of the Cinergy merger, and references to amounts for periods after the closing of the merger relate to New Duke Energy. Cinergy's results have been included in the accompanying Consolidated Statements of Operations from the effective date of acquisition and thereafter (see "Cinergy Merger" in Note 2 to the Consolidated Financial Statements, "Acquisitions and Dispositions"). Both Old Duke Energy and New Duke Energy are referred to as Duke Energy hereinafter.

In conjunction with Duke Energy's merger with Cinergy, effective with the second quarter ended June 30, 2006, Duke Energy adopted new business segments that management believes properly align the various operations of Duke Energy with how the chief operating decision maker views the business. Duke Energy operates the following business units: U.S. Franchised Electric and Gas, Natural Gas Transmission, Field Services, Commercial Power, International Energy and Duke Energy's 50% interest in the Crescent JV (Crescent). Prior to Duke Energy's sale of an effective 50% ownership interest in Crescent in September 2006 (see below), this segment represented Duke Energy's 100% ownership of Crescent Resources, LLC. Duke Energy's chief operating decision maker regularly reviews financial information about each of these business units in deciding how to allocate resources and evaluate performance. All of the Duke Energy business units are considered reportable segments under Statement of Financial Accounting Standards (SFAS) No. 131, "Disclosures about Segments of an Enterprise and Related Information." (See Note 3 to the Consolidated Financial Statements, "Business Segments," for additional information, including financial information about each business unit and geographic areas.)

Prior to the September 2005 announcement of the exiting of the majority of former Duke Energy North America's (DENA) businesses, former DENA's operations were considered a separate reportable segment. The term DENA, as used throughout the Notes to Consolidated Financial Statements, refers to the former merchant generation operations in the Western and Eastern U.S., as well as operations in the Midwest and Southeast. Under Duke Energy's new segment structure, the merchant generation operations of the Midwest and Southeast are presented in continuing operations as a component of the Commercial Power segment for all periods presented and the Western and Eastern operations are presented as a component of discontinued operations within Other for all periods presented. Prior to the change in business segments, former DENA's continuing operations, which primarily include the merchant generation operations in the Midwest and Southeast, were included in Other in 2005 and as a component of the DENA segment in all prior periods, and discontinued operations were included in the former DENA segment for all periods.

U.S. Franchised Electric and Gas generates, transmits, distributes and sells electricity in central and western North Carolina, western South Carolina, southwestern Ohio, central and southern Indiana, and northern Kentucky. U.S. Franchised Electric and Gas also transports and sells natural gas in southwestern Ohio and northern Kentucky. It conducts operations primarily through Duke Energy Carolinas, Duke Energy Ohio, Inc. (Duke Energy Ohio), Duke Energy Indiana, Inc. (Duke Energy Indiana) and Duke Energy Kentucky, Inc. (Duke Energy Kentucky). These electric and gas operations are subject to the rules and regulations of the Federal Energy Regulatory Commission (FERC), the North Carolina Utilities Commission (NCUC), the Public Service Commission of South Carolina (PSCSC), the Public Utilities Commission of Ohio (PUCO), the Indiana Utility Regulatory Commission (IURC) and the Kentucky Public Service Commission (KPSC).

Natural Gas Transmission provides transportation and storage of natural gas for customers in various regions of the Eastern and Southeastern United States, the Maritimes Provinces and the Pacific Northwest in the United States and Canada and in the province of Ontario in Canada. Natural Gas Transmission also provides natural gas sales and distribution service to retail customers in Ontario, and natural gas gathering and processing services to customers in Western Canada. Natural Gas Transmission does business primarily through Duke Energy Gas Transmission, LLC (DEGT). DEGT's natural gas transmission and storage operations in the U.S. are primarily subject to the FERC's and the U.S. Department of Transportation's (DOT's) rules and regulations, while natural gas gathering, processing, transmission, distribution and storage operations in Canada are primarily subject to the rules and regulations of the National Energy Board (NEB) and the Ontario Energy Board (OEB). As discussed below, effective January 2, 2007, Duke Energy consummated its spin-off of the natural gas businesses (Spectra Energy Corp. (Spectra Energy)), which includes the Natural Gas Transmission business segment, to shareholders.

Field Services includes Duke Energy's investment in DCP Midstream, LLC (formerly Duke Energy Field Services, LLC (DEFS)), which gathers, compresses, processes, transports, trades and markets, and stores natural gas. DEFS also fractionates, transports, gathers, treats, processes, trades and markets, and stores natural gas liquids (NGLs). DEFS is 50% owned by ConocoPhillips and 50% owned by Duke Energy. DEFS gathers raw natural gas through gathering systems located in major natural gas producing regions: Permian, Mid-Continent, East Texas-North Louisiana, South, Central, Rocky Mountain, and Gulf Coast. As discussed below, effective January 2, 2007, Duke Energy consummated its spin-off of Spectra Energy, which includes Duke Energy's 50% ownership interest in DEFS, to shareholders.

In July 2005, Duke Energy completed the agreement with ConocoPhillips, Duke Energy's co-equity owner in DEFS, to reduce Duke Energy's ownership interest in DEFS from 69.7% to 50% (the DEFS disposition transaction), which resulted in Duke Energy and ConocoPhillips becoming equal 50% owners in DEFS. As a result of the DEFS disposition transaction, Duke Energy deconsolidated its investment in DEFS and subsequently has accounted for it as an investment utilizing the equity method of accounting.

In June 2006, the Board of Directors of Duke Energy authorized management to pursue a plan to create two separate publicly traded companies by spinning off Duke Energy's natural gas businesses to Duke Energy shareholders. On January 2, 2007, Duke Energy completed the spin-off of its natural gas businesses, including Duke Energy's 50% interest in DEFS, to shareholders. The new natural gas business, which is named Spectra Energy, consists principally of the operations of Spectra Energy Capital LLC (Spectra Energy Capital, formerly Duke Capital LLC), excluding certain operations which were transferred from Spectra Energy Capital to Duke Energy in December 2006, primarily International Energy and Duke Energy's effective 50% interest in the Crescent JV. The use of the term Spectra Energy Capital relates to operations of the former Duke Capital LLC or the post-spin Spectra Energy Capital, as the context requires. Approximately $20 billion of assets, $13 billion of liabilities (which includes approximately $8.6 billion of debt issued by Spectra Energy Capital and its consolidated subsidiaries), and $7 billion of common stockholders' equity were distributed from Duke Energy as of the date of the spin-off. Assets and liabilities of entities included in the spin-off of Spectra Energy were transferred from Duke Energy on a historical cost basis on the date of the spin-off transaction.

The decision to spin off the natural gas businesses is expected to deliver long-term value to shareholders. The historical results of the natural gas businesses are expected to be treated as discontinued operations at Duke Energy in future periods beginning with the first quarter of 2007. The primary businesses remaining in Duke Energy post-spin are principally the U.S. Franchised Electric and Gas business segment, the Commercial Power business segment, the International Energy business segment and Duke Energy's 50% interest in the Crescent JV (see below).

Commercial Power owns, operates and manages non-regulated merchant power plants and engages in the wholesale marketing and procurement of electric power, fuel and emission allowances related to these plants as well as other contractual positions. Commercial Power also develops and implements customized energy solutions. Commercial Power's generation asset fleet consists of Duke Energy Ohio's non-regulated generation in Ohio, acquired from Cinergy in April 2006, and the five Midwestern gas-fired merchant generation assets that were a portion of former DENA. Commercial Power's assets comprise approximately 8,100 megawatts of power generation primarily located in the Midwestern United States. The asset portfolio has a diversified fuel mix with base-load and mid-merit coal-fired units as well as combined cycle and peaking natural gas-fired units. Most of the generation asset output in Ohio has been contracted through the Rate Stabilization Plan (RSP). For more information on the RSP, see "Commercial Power" section below.

International Energy operates and manages power generation facilities, and engages in sales and marketing of electric power and natural gas outside the U.S. and Canada. It conducts operations primarily through Duke Energy International, LLC (DEI) and its activities target power generation in Latin America. Additionally, International Energy owns equity investments in Saudi Arabia, Mexico, and Greece.

Crescent develops and manages high-quality commercial, residential and multi-family real estate projects primarily in the Southeastern and Southwestern United States. Some of these projects are developed and managed through joint ventures. Crescent also manages "legacy" land holdings in North and South Carolina.

On September 7, 2006, an indirect wholly owned subsidiary of Duke Energy closed an agreement to create a joint venture of Crescent (the Crescent JV) with Morgan Stanley Real Estate Fund V U.S., L.P. (MSREF) and other affiliated funds controlled by Morgan Stanley (collectively the MS Members). Under the agreement, the Duke Energy subsidiary contributed all of the membership interests in Crescent to a newly-formed joint venture, which was ascribed an enterprise value of approximately $2.1 billion as of December 31, 2005. In conjunction with the formation of the Crescent JV, the joint venture, Crescent and Crescent's subsidiaries entered into a credit agreement with third party lenders under which Crescent borrowed approximately $1.21 billion, net of transaction costs, of which approximately $1.19 billion was immediately distributed to Duke Energy. Immediately following the debt transaction, the MS Members collectively acquired a 49% membership interest in the Crescent JV from Duke Energy for a purchase price of approximately $415 million. A 2% interest in the Crescent JV was also issued by the joint venture to the President and Chief Executive Officer of Crescent which is subject to forfeiture if the executive voluntarily leaves the employment of the Crescent JV within a three year period. Additionally, this 2% interest can be put back to the Crescent JV after three years or possibly earlier upon the occurrence of certain events at an amount equal to 2% of the fair value of the Crescent JV's equity as of the put date. Therefore, the Crescent JV will accrue the obligation related to the put as a liability over the three year forfeiture period. Accordingly, Duke Energy has an effective 50% ownership in the equity of Crescent JV for financial reporting purposes. Duke Energy's investment in the Crescent JV has been accounted for as an equity method investment for periods after September 7, 2006.

The remainder of Duke Energy's operations is presented as "Other". While it is not considered a business segment, Other primarily includes the following:

- The remaining portion of Duke Energy's business formerly known as DENA, including its 100% owned affiliates Duke Energy Marketing America, LLC and Duke Energy Marketing Canada Corp. Duke Energy also participates in Duke Energy Trading and Marketing, LLC (DETM). DETM is 40% owned by ExxonMobil Corporation and 60% owned by Duke Energy. During the third quarter of 2005, Duke Energy's Board of Directors authorized and directed management to execute the sale or disposition of substantially all of former DENA's remaining assets and contracts outside the Midwestern United States and certain contractual positions related to the Midwestern assets. The exit plan was completed in the second quarter of 2006 (see Note 13 to the Consolidated Financial Statements, "Discontinued Operations and Assets Held for Sale"). In addition, management will continue to wind down the limited remaining operations of DETM. The results of operations for most of former DENA's businesses which Duke Energy has exited have been reflected as discontinued operations in the accompanying Consolidated Statements of Operations for all years presented.

- Certain unallocated corporate costs, certain discontinued hedges, DukeNet Communications, LLC (DukeNet), Bison Insurance Company Limited (Bison), Duke Energy's wholly owned, captive insurance subsidiary, Cinergy's equity financing business and Duke Energy's 50% interest in Duke/Fluor Daniel (D/FD). DukeNet develops, owns and operates a fiber optic communications network, primarily in the Carolinas, serving wireless, local and long-distance communications companies, internet service providers and other businesses and organizations. Bison's principal activities, as a captive insurance entity, include the insurance and reinsurance of various business risks and losses, such as workers compensation, property, business interruption and general liability of subsidiaries and affiliates of Duke Energy. Bison also participates in reinsurance activities with certain third parties, on a limited basis. Cinergy has a business which invests in start up businesses utilizing new energy technologies as well as technologies utilizing energy infrastructure, such as broadband over power line services. D/FD is a 50/50 partnership between subsidiaries of Duke Energy and Fluor Corporation (Fluor). During 2003, Duke Energy and Fluor announced that they would dissolve D/FD and adopted a plan for an orderly wind-down of D/FD's business. The wind-down has been substantially completed as of December 31, 2006. Previously, D/FD provided comprehensive engineering, procurement, construction, commissioning and operating plant services for fossil-fueled electric power generating facilities worldwide.

Duke Energy is a Delaware corporation. Its principal executive offices are located at 526 South Church Street, Charlotte, North Carolina 28202-1803. The telephone number is 704-594-6200. Duke Energy electronically files reports with the Securities and Exchange Commission (SEC), including annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, proxies and amendments to such reports. The public may read and copy any materials that Duke Energy files with the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. The SEC also maintains an internet site that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC at *http://www.sec.gov*. Additionally, information about Duke Energy, including its reports filed with the SEC, is available through Duke Energy's web site at *http://www.duke-energy.com*. Such reports are accessible at no charge through Duke Energy's web site and are made available as soon as reasonably practicable after such material is filed with or furnished to the SEC.

Terms used to describe Duke Energy's business are defined below.

Accrual Model of Accounting (Accrual Model). An accounting term used by Duke Energy to refer to contracts for which there is generally no recognition in the Consolidated Statements of Operations for any changes in fair value until the service is provided, the associated delivery period occurs or there is hedge ineffectiveness. As discussed further in Note 1 to the Consolidated Financial Statements, "Summary of Significant Accounting Policies," this term is applied to derivative contracts that are accounted for as cash flow hedges, fair value hedges, and normal purchases or sales, as well as to non-derivative contracts used for commodity risk management purposes. As this term is not explicitly defined within U.S. Generally Accepted Accounting Principles (GAAP), Duke Energy's application of this term could differ from that of other companies.

Allowance for Funds Used During Construction (AFUDC). An accounting convention of regulators that represents the estimated composite interest costs of debt and a return on equity funds used to finance construction. The allowance is capitalized in the property accounts and included in income.

British Thermal Unit (Btu). A standard unit for measuring thermal energy or heat commonly used as a gauge for the energy content of natural gas and other fuels.

Cubic Foot (cf). The most common unit of measurement of gas volume; the amount of natural gas required to fill a volume of one cubic foot under stated conditions of temperature, pressure and water vapor.

Decommissioning. The process of closing down a nuclear facility and reducing the residual radioactivity to a level that permits the release of the property and termination of the license. Nuclear power plants are required by the Nuclear Regulatory Commission (NRC) to set aside funds for their decommissioning costs during operation.

Derivative. A financial instrument or contract in which its price is based on the value of underlying securities, equity indices, debt instruments, commodities or other benchmarks or variables. Often used to hedge risk, derivatives involve the trading of rights or obligations, but not the direct transfer of property. Gains or losses on derivatives are often settled on a net basis.

Distribution. The system of lines, transformers, switches and mains that connect electric and natural gas transmission systems to customers.

Energy Marketing. Identification and execution of physical energy related transactions, generally with customized provisions to meet the needs of the customer or supplier, throughout the supply chain.

Environmental Protection Agency (EPA). The U.S. agency that is responsible for researching and setting national standards for a variety of environmental programs, and delegates to states the responsibility for issuing permits and for monitoring and enforcing compliance.

Federal Energy Regulatory Commission (FERC). The U.S. agency that regulates the transportation of electricity and natural gas in interstate commerce and authorizes the buying and selling of energy commodities at market-based rates.

Forward Contract. A contract in which the buyer is obligated to take delivery, and the seller is obligated to deliver a specified amount of a commodity with a predetermined price formula on a specified future date, at which time payment is due in full.

Fractionation/Fractionate. The process of separating liquid hydrocarbons from natural gas into propane, butane, ethane and other related products.

Futures Contract. A contract, usually exchange traded, in which the buyer is obligated to take delivery and the seller is obligated to deliver a fixed amount of a commodity at a predetermined price on a specified future date.

Gathering System. Pipeline, processing and related facilities that access production and other sources of natural gas supplies for delivery to mainline transmission systems.

Generation. The process of transforming other forms of energy, such as nuclear or fossil fuels, into electricity. Also, the amount of electric energy produced, expressed in gigawatt-hours.

Independent System Operator (ISO). An entity that acts as the transmission provider for a regional transmission system, providing customers access to the system and clearing all bi-lateral contract requests for use of the electric transmission system. An ISO also shares responsibility for maintaining bulk electric system reliability.

Integrated Resource Planning. The process typically utilized by regulated utilities in conjunction with state regulatory bodies for forecasting and planning the need for generation and transmission facilities.

Light-off Fuel. Fuel oil used to light the coal prior to generating electricity.

Liquefied Natural Gas (LNG). Natural gas that has been converted to a liquid by cooling it to minus 260 degrees Fahrenheit.

Liquidity. The ease with which assets or products can be traded without dramatically altering the current market price

Local Distribution Company (LDC). A company that obtains the major portion of its revenues from the operations of a retail distribution system for the delivery of electricity or gas for ultimate consumption.

Mark-to-Market Model of Accounting (MTM Model). An accounting term used by Duke Energy to refer to derivative contracts for which an asset or liability is recognized at fair value and the change in the fair value of that asset or liability is recognized in the Consolidated Statements of Operations. As discussed further in Note 1 to the Consolidated Financial Statements, "Summary of Significant Accounting Policies," this term is applied to trading and undesignated non-trading derivative contracts. As this term is not explicitly defined within GAAP, Duke Energy's application of this term could differ from that of other companies

Natural Gas. A naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in porous geological formations beneath the earth's surface, often in association with petroleum. The principal constituent is methane.

Natural Gas Liquids (NGLs). Liquid hydrocarbons extracted during the processing of natural gas. Principal commercial NGLs include butanes, propane, natural gasoline and ethane

No-notice Bundled Service. A pipeline delivery service which allows customers to receive or deliver gas on demand without making prior nominations to meet service needs and without paying daily balancing and scheduling penalties.

Novation. The substitution of a new obligation or contract for an old one by the mutual agreement of all parties concerned.

Nuclear Regulatory Commission (NRC). The U.S. agency responsible for regulating the Nation's civilian use of byproduct, source, and special nuclear materials to ensure adequate protection of public health and safety, to promote the common defense and security, and to protect the environment. The NRC's scope of responsibility includes regulation of: commercial nuclear power reactors, including nonpower research, test and training reactors; fuel cycle facilities, including medical, academic and industrial uses of nuclear materials; and the transport, storage and disposal of nuclear materials and waste.

Origination. Identification and execution of physical energy related transactions, generally with customized provisions to meet the needs of the customer or supplier, throughout the supply chain.

Option. A contract that gives the buyer a right but not the obligation to purchase or sell an underlying asset at a specified price at a specified time

Peak Load. The amount of electricity required during periods of highest demand. Peak periods fluctuate by season, generally occurring in the morning hours in winter and in late afternoon during the summer.

Portfolio. A collection of assets, liabilities, transactions, or trades.

Regional Transmission Organization (RTO). An independent entity which is established to have "functional control" over utilities' transmission systems, in order to expedite transmission of electricity. RTO's typically operate markets within their territories.

Reliability Must Run. Generation that an ISO determines is required to be on-line to meet applicable reliability criteria requirements.

Residue Gas. Gas remaining after the processing of natural gas

Spark Spread. The difference between the value of electricity and the value of the gas required to generate the electricity at a specified heat rate

Swap. A contract to exchange cash flows in the future according to a prearranged formula.

Throughput. The amount of natural gas or NGLs transported through a pipeline system.

Tolling. Arrangement whereby a buyer provides fuel to a power generator and receives generated power in return for a specified fee.

Transmission System (Electric). An interconnected group of electric transmission lines and related equipment for moving or transferring electric energy in bulk between points of supply and points at which it is transformed for delivery over a distribution system to customers, or for delivery to other electric transmission systems.

Transmission System (Natural Gas). An interconnected group of natural gas pipelines and associated facilities for transporting natural gas in bulk between points of supply and delivery points to industrial customers, LDCs, or for delivery to other natural gas transmission systems.

Volatility. An annualized measure of the fluctuation in the price of an energy contract.

Watt. A measure of power production or usage equal to one joule per second.

The following sections describe the business and operations of each of Duke Energy's business segments. (For more information on the operating outlook of Duke Energy and its segments, see "Management's Discussion and Analysis of Financial Condition and Results of Operations, Introduction—Executive Overview and Economic Factors for Duke Energy's Business". For financial information on Duke Energy's business segments, see Note 3 to the Consolidated Financial Statements, "Business Segments.")

U.S. FRANCHISED ELECTRIC AND GAS

Service Area and Customers

U.S. Franchised Electric and Gas generates, transmits, distributes and sells electricity. U.S. Franchised Electric and Gas also transports and sells natural gas. It conducts operations primarily through Duke Energy Carolinas, Duke Energy Ohio, Duke Energy Indiana and Duke Energy Kentucky (Duke Energy Ohio, Duke Energy Indiana and Duke Energy Kentucky collectively referred to as Duke Energy Midwest). Its service area covers about 47,000 square miles with an estimated population of 10 million in central and western North Carolina, western South Carolina, southwestern Ohio, central and southern Indiana, and northern Kentucky. U.S. Franchised Electric and Gas supplies electric service to approximately 3.9 million residential, commercial and industrial customers over 146,700 miles of distribution lines and a 20,700-mile transmission system. U.S. Franchised Electric and Gas provides domestic regulated transmission and distribution services for natural gas to approximately 500,000 customers via approximately 8,900 miles of gas mains (gas distribution lines that serve as a common source of supply for more than one service line) and service lines. Electricity is also sold wholesale to incorporated municipalities and to public and private utilities. In addition, municipal and cooperative customers who purchased portions of the Catawba Nuclear Station may also buy power from a variety of suppliers including Duke Energy Carolinas, through contractual agreements. (For more information on the Catawba Nuclear Station joint ownership, see Note 5 to the Consolidated Financial Statements, "Joint Ownership of Generating and Transmission Facilities.")

Duke Energy Carolinas' service area has a diversified commercial and industrial presence. Manufacturing continues to be the largest contributor to the Carolinas' economy. Other sectors such as information, financial and real estate services are growing.

The textile industry, rubber and plastic products, chemicals and computer products are the most significant contributors to the area's manufacturing output and Duke Energy Carolinas' industrial sales revenue for 2006. Motor vehicle parts, building materials and electrical & electronic equipment manufacturing also have a strong impact in the area's economic growth and the region's industrial sales. The textile industry, while in decline, is the largest industry served in the Carolinas.

Duke Energy Carolinas has business development strategies to leverage the competitive advantages of North Carolina and South Carolina to attract and expand advanced manufacturing business in the region's service territory. These competitive advantages, including a quality workforce, strong educational institutions and superior transportation infrastructure, were key factors in bringing in new customers in the plastics, pharmaceuticals, building materials and data processing industries. The success in attracting new companies as well as expanding the operations of existing customers substantially offsets the sales declines in the textile and furniture industries in 2006.

Industries of major economic significance in Duke Energy Indiana's service territory include chemicals, primary metals, and transportation. Other significant industries operating in the area include stone, clay and glass, food products, paper, and other manufacturing. Key sectors among commercial customers include education and retail trade.

Duke Energy Indiana's business development strategies leveraged the competitive advantages of Indiana to attract new advanced manufacturing, logistics, life sciences and data center business to Duke Energy Indiana's service territory. These advantages, including competitive electric rates, a strong transportation network, excellent institutions of higher learning, and a quality workforce, were key in attracting new customers and encouraging existing customer expansions. This ability to attract business investment in the service territory helped balance the slight decline in sales in the chemical, food and transportation equipment sector.

Duke Energy Ohio and Duke Energy Kentucky's service area has a diversified commercial and industrial presence. Major components of the economy include manufacturing, real estate & rental leasing, wholesale trade, financial and insurance services, retail trade, education, healthcare and professional/business services. Cincinnati is positioned to become a healthcare hub and the presence of non-durable manufacturing makes the area less vulnerable to economic fluctuations than other areas.

The primary metals industry, transportation equipment, chemicals, and paper and plastics are the most significant contributors to the area's manufacturing output and Duke Energy Ohio and Duke Energy Kentucky's industrial sales revenue for 2006. Food, beverage and tobacco, fabricated metals, and electronics also have a strong impact on the area's economic growth and the region's industrial sales.

Duke Energy Ohio and Duke Energy Kentucky have business development strategies to leverage the competitive advantages of the Greater Cincinnati Region to attract and expand advanced manufacturing businesses. The availability of a highly skilled workforce, superior highway access, low cost of living, and proximity to markets and raw materials were key factors in attracting new customers in the transportation, food manufacturing, chemical manufacturing, plastics and data processing industries.

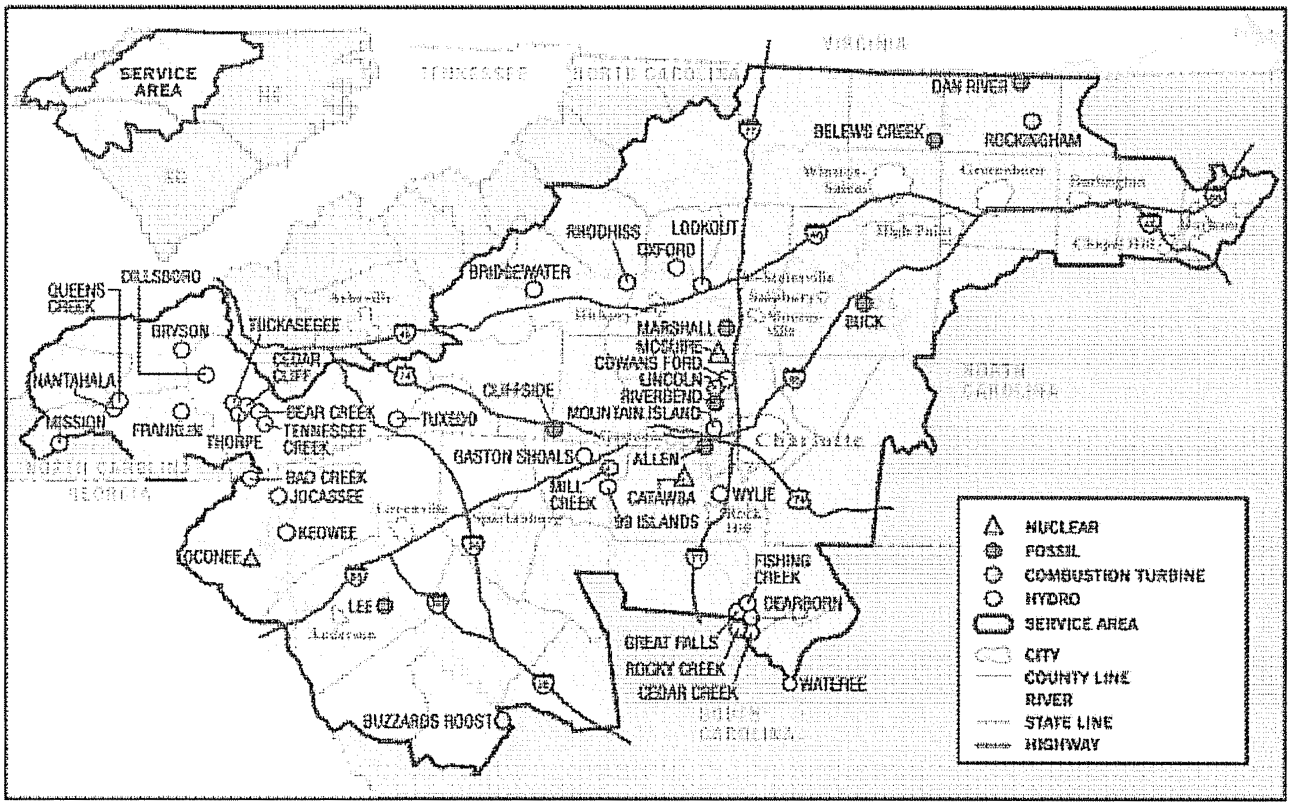
The number of residential and commercial customers within the U.S. Franchised Electric and Gas' service territory continues to increase. Sales to these customers are increasing due to the growth in these sectors. As sales to residential and commercial customers increase, the consistent level of sales to industrial customers becomes a smaller, yet still significant, portion of U.S. Franchised Electric and Gas sales.

U.S. Franchised Electric and Gas' costs and revenues are influenced by seasonal patterns. Peak sales occur during the summer and winter months, resulting in higher revenue and cash flows during those periods. By contrast, fewer sales occur during the spring and fall allowing for scheduled plant maintenance during those periods.

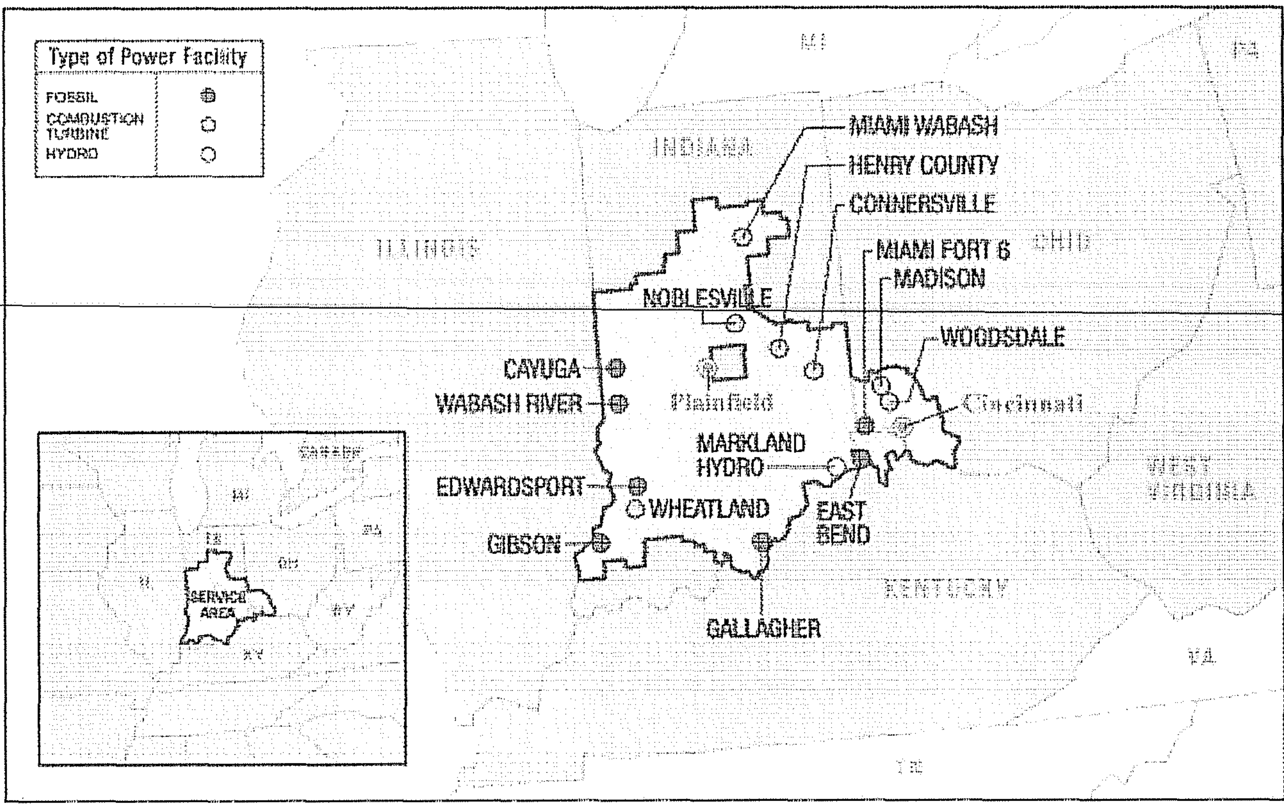
The following maps show the U.S. Franchised Electric and Gas' service territories and operating facilities.

Duke Energy – Carolinas

Power Generation Regulated Facilities



Duke Energy – Midwest Power Generation
Regulated Facilities



Energy Capacity and Resources

Electric energy for U.S. Franchised Electric and Gas' customers is generated by three nuclear generating stations with a combined net capacity of 5,020 megawatts (MW) (including Duke Energy's 12.5% ownership in the Catawba Nuclear Station), fifteen coal-fired stations with a combined net capacity of 13,552 MW, thirty-one hydroelectric stations (including two pumped-storage facilities) with a combined net capacity of 3,213 MW, fifteen combustion turbine (CT) stations burning natural gas, oil or other fuels with a combined net capacity of 5,245 MW and two combined cycle (CC) stations burning natural gas or synthetic gas with a combined net capacity of 560 MW. The CT stations include the 2006 acquisition of the Rockingham CT facility (825 MW) from Dynegy Power Marketing, Inc. The acquisition was completed November 10, 2006 and was the most recent addition to U.S. Franchised Electric and Gas' resource capability. Energy and capacity are also supplied through contracts with other generators and purchased on the open market. Factors that could cause U.S. Franchised Electric and Gas to purchase power for its customers include generating plant outages, extreme weather conditions, summer reliability, growth, and price. U.S. Franchised Electric and Gas has interconnections and arrangements with its neighboring utilities to facilitate planning, emergency assistance, sale and purchase of capacity and energy, and reliability of power supply.

In December 2006, Duke Energy announced an agreement to purchase a portion of Saluda River Electric Cooperative, Inc.'s ownership interest in the Catawba Nuclear Station. Under the terms of the agreement, Duke Energy will pay approximately $158 million for the additional ownership interest of the Catawba Nuclear Station. Following the closing of the transaction, Duke Energy will own approximately 19 percent of Catawba Nuclear Station. This transaction, which is expected to close prior to September 30, 2008, is subject to approval by various state and federal agencies.

U.S. Franchised Electric and Gas' generation portfolio is a balanced mix of energy resources having different operating characteristics and fuel sources designed to provide energy at the lowest possible cost to meet its obligation to serve native-load customers. All options including owned generation resources and purchased power opportunities are continually evaluated on a real-time basis to select and dispatch the lowest-cost resources available to meet system load requirements. The vast majority of customer energy needs are met by large, low-energy-production-cost nuclear and coal-fired generating units that operate almost continuously (or at baseload levels). In 2006, approximately 98.8% of the total generated energy came from U.S. Franchised Electric and Gas' low-cost, efficient nuclear and coal units (51.9% coal and 46.9% nuclear). The remaining energy needs were supplied by hydroelectric, CT and CC generation or economical purchases from the wholesale market.

Hydroelectric (both conventional and pumped storage) in the Carolinas and gas/oil CT and CC stations in both the Carolinas and Midwest operate primarily during the peak-hour load periods (at peaking levels) when customer loads are rapidly changing. CT's and CC's produce energy at higher production costs than either nuclear or coal, but are less expensive to build and maintain, and can be rapidly started or stopped as needed to meet changing customer loads. Hydroelectric units produce low-cost energy, but their operations are limited by the availability of water flow.

U.S. Franchised Electric and Gas' major pumped-storage hydroelectric facilities offer the added flexibility of using low-cost off-peak energy to pump water that will be stored for later generation use during times of higher-cost on-peak generation periods. These facilities allow U.S. Franchised Electric and Gas to maximize the value spreads between different high- and low-cost generation periods.

U.S. Franchised Electric and Gas is engaged in planning efforts to meet projected load growth in its service territory. Long-term projections indicate a need for significant capacity additions, which may include new nuclear, coal and integrated gasification combined cycle (IGCC) facilities. Because of the long lead times required to develop such assets, U.S. Franchised Electric and Gas is taking steps now to ensure those options are available. For example, Duke Energy Carolinas filed an application with the NCUC for a Certificate of Public Convenience and Necessity (CPCN) on June 2, 2006 for regulatory approval to build the Cliffside Project consisting of two 800 MW supercritical coal units at the existing Cliffside Steam Station, located in Rutherford and Cleveland Counties of North Carolina. Steps are also being taken to maintain the option to bring the Cliffside project on-line as early as 2011. On February 28, 2007, the NCUC issued a notice of decision approving the construction of one unit at the Cliffside Steam Station. The NCUC stated that it will issue a full order in the near future. Duke Energy will review the NCUC's order, once issued, and determine whether to proceed with the Cliffside Project or consider other alternatives, including additional gas fired generation. In September 2006, Duke Energy Indiana and Vectren Energy Delivery of Indiana, Inc. filed a joint petition with the IURC seeking a CPCN for constructing a 630 MW IGCC power plant at Duke Energy Indiana's Edwardsport Generating Station in Knox County, Indiana. In addition, Duke Energy Carolinas is preparing an application for a Combined Construction and Operating License from the NRC, with the objective of potentially bringing a new nuclear facility on line by 2016. Although U.S. Franchised Electric and Gas is progressing with these efforts, final decisions regarding the development of new power facilities will be driven by realized demand, market conditions and other strategic considerations.

In evaluating the construction of several large, new electric generating plants in North Carolina, South Carolina, and Indiana, Duke Energy has begun to see significant increases in the estimated costs of these projects driven by strong domestic and international demand for the material, equipment, and labor necessary to construct these facilities. In October 2006, Duke Energy made a filing with the NCUC related to the Duke Energy Carolinas' request for a CPCN for the Cliffside project. In this filing, Duke Energy stated that due to the rising costs described above, the cost of building the Cliffside units could be approximately $3 billion, excluding allowance for funds used during construction (AFUDC). The costs described above are expected to continue to increase causing the overall cost of the Cliffside project to increase, until such time as the NCUC issues a CPCN and Duke Energy is able to enter into definitive agreements with necessary material and service providers. In November 2006, Duke Energy received approval for nearly $260 million of future federal tax credits related to costs to be incurred for the modernization of the Cliffside facility as well as the IGCC plant in Indiana.

Duke Energy Indiana's estimated costs associated with the potential construction of an IGCC plant in Indiana have also increased. Duke Energy Indiana's publicly filed testimony with the IURC on October 24, 2006 indicates that industry (Electric Power Research Institute) estimates of total capital requirement for a facility of this type and size are now in the range of $1.6 billion to $2.1 billion (including escalation to 2011 and owner's specific site costs).

Fuel Supply

U.S. Franchised Electric and Gas relies principally on coal and nuclear fuel for its generation of electric energy. The following table lists U.S. Franchised Electric and Gas' sources of power and fuel costs for the three years ended December 31, 2006.

	Generation by Source (Percent)			Cost of Delivered Fuel per Net Kilowatt-hour Generated (Cents)		
	2006	2005 (d)	2004 (d)	2006	2005 (d)	2004 (d)
Coal	63.4	52.5	52.2	2.16	2.14	1.84
Nuclear(a)	35.1	45.7	45.9	0.42	0.41	0.41
Oil and gas(b)	0.6	0.1	0.2	12.67	28.83	16.79
All fuels (cost based on weighted average)(a)	99.1	98.3	98.3	1.61	1.36	1.20
Hydroelectric(c)	0.9	1.7	1.7			
	100.0	100.0	100.0			

(a) *Statistics related to nuclear generation and all fuels reflect* U.S. Franchised Electric and Gas' 12.5% ownership interest in the Catawba Nuclear Station.

(b) Cost statistics include amounts for light-off fuel at U.S. Franchised Electric and Gas' coal-fired stations.

(c) *Generating figures are net of output required to replenish pumped storage facilities during off-peak periods.*

(d) Excludes the Midwest.

Coal. U.S. Franchised Electric and Gas meets its coal demand in the Carolinas and Midwest through a portfolio of purchase supply contracts and spot agreements. Large amounts of coal are purchased under supply contracts with mining operators who mine both underground and at the surface. U.S. Franchised Electric and Gas uses spot-market purchases to meet coal requirements not met by supply contracts. Expiration dates for its supply contracts, which have various price adjustment provisions and market re-openers, range from 2007 to 2016. U.S. Franchised Electric and Gas expects to renew these contracts or enter into similar contracts with other suppliers for the quantities and quality of coal required as existing contracts expire, though prices will fluctuate over time as coal markets change. The coal purchased for the Carolinas is primarily produced from mines in eastern Kentucky, West Virginia and southwestern Virginia. The coal purchased for the Midwest is primarily produced in Indiana, Illinois, and Kentucky. U.S. Franchised Electric and Gas has an adequate supply of coal to fuel its current and projected operations.

The current average sulfur content of coal purchased by U.S. Franchised Electric and Gas for the Carolinas is approximately 1%, however, as several Carolinas coal plants bring on scrubbers over the next several years the sulfur content of coal purchased could increase as higher sulfur coal options are considered. The current average sulfur content of coal purchased by U.S. Franchised Electric and Gas for the Midwest is approximately 2%. Coupled with the use of available sulfur dioxide emission allowances on the open market, this satisfies the current emission limitations for sulfur dioxide for existing facilities in the Carolinas and Midwest.

Gas. U.S. Franchised Electric and Gas is responsible for the purchase and the subsequent delivery of natural gas to native load customers in the Midwest. U.S. Franchised Electric and Gas' natural gas procurement strategy is to buy firm natural gas supplies (natural gas intended to be available at all times) and firm interstate pipeline transportation capacity during the winter season (November through March) and during the non-heating season (April through October) through a combination of firm supply and transportation capacity along with spot supply and interruptible transportation capacity. This strategy allows U.S. Franchised Electric and Gas to assure reliable natural gas supply for its high priority (non-curtailable) firm customers during peak winter conditions and provides U.S. Franchised Electric and Gas the flexibility to reduce its contract commitments if firm customers choose alternate gas suppliers under U.S. Franchised Electric and Gas' customer choice/gas transportation programs. In 2006, firm supply purchase commitment agreements provided approximately 91% of the natural gas supply, with the remaining gas purchased on the spot market. These firm supply agreements feature two levels of gas supply, specifically (1) baseload, which is a continuous supply to meet normal demand requirements, and (2) swing load, which is gas available on a daily basis to accommodate changes in demand due primarily to changing weather conditions.

U.S. Franchised Electric and Gas manages natural gas procurement-price volatility mitigation programs for Duke Energy Ohio and Duke Energy Kentucky. These programs pre-arrange between 25-75% of winter heating season baseload gas requirements and up to 25-50% of summer season baseload requirements up to three years in advance of the delivery month. Duke Energy Ohio and Duke Energy Kentucky use primarily fixed-price forward contracts and contracts with a ceiling and floor on the price. As of December 31, 2006, Duke Energy Ohio and Duke Energy Kentucky, combined, had hedged approximately 73% of their winter 2006/2007 base load requirements.

Nuclear. Developing nuclear generating fuel generally involves the mining and milling of uranium ore to produce uranium concentrates, the conversion of uranium concentrates to uranium hexafluoride gas, enrichment of that gas, and then the fabrication of the enriched uranium hexafluoride into usable fuel assemblies.

U.S. Franchised Electric and Gas has contracted for uranium materials and services required to fuel the Oconee, McGuire and Catawba Nuclear Stations in the Carolinas. Uranium concentrates, conversion services and enrichment services are primarily met through a diversified portfolio of long-term supply contracts. The contracts are diversified by supplier, country of origin and pricing. U.S. Franchised Electric and Gas staggers its contracting so that its portfolio of long-term contracts covers the majority of its fuel requirements at Oconee, McGuire and Catawba in the near term, but so that its level of coverage decreases over time into the future. Due to the technical complexities of changing suppliers of fuel fabrication services, U.S. Franchised Electric and Gas generally sole sources these services to a single domestic supplier on a plant-by-plant basis using multi-year contracts.

Based on current projections, U.S. Franchised Electric and Gas' existing portfolio of contracts will meet the requirements of Oconee, McGuire and Catawba Nuclear Stations through the following years:

Nuclear Station	Uranium Material	Conversion Service	Enrichment Service	Fabrication Service
Oconee	2011	2011	2009	2015
McGuire	2011	2011	2009	2015
Catawba	2011	2011	2009	2014

After the years indicated above, a portion of the fuel requirements at Oconee, McGuire and Catawba are covered by long-term contracts. For requirements not covered under long-term contracts, Duke Energy believes it will be able to renew contracts as they expire, or enter into similar contractual arrangements with other suppliers of nuclear fuel materials and services. Near-term requirements not met by long-term supply contracts have been and are expected to be fulfilled with uranium spot market purchases.

Duke Energy Carolinas has entered into a contract with Shaw AREVA MOX Services (MOX Services) (formerly Duke COGEMA Stone & Webster, LLC (DCS)) under which Duke Energy Carolinas has agreed to prepare the McGuire and Catawba nuclear reactors for use of mixed-oxide fuel and to purchase mixed-oxide fuel for use in such reactors. Mixed-oxide fuel will be fabricated by MOX Services from the U.S. government's excess plutonium from its nuclear weapons programs and is similar to conventional uranium fuel. Before using the fuel, Duke Energy Carolinas must apply for and obtain amendments to the facilities' operating licenses from the NRC. On March 3, 2005, the NRC issued amendments to Catawba Nuclear Station's operating licenses to allow the receipt and use of four mixed oxide fuel lead assemblies. These four lead assemblies completed their first cycle of irradiation on November 11, 2006 and have been inserted for a second cycle of irradiation in Unit 1 of the Catawba Nuclear Station.

Inventory

Generation of electricity is capital-intensive. U.S. Franchised Electric and Gas must maintain an adequate stock of fuel, materials and supplies in order to ensure continuous operation of generating facilities and reliable delivery to customers. As of December 31, 2006, the inventory balance for U.S. Franchised Electric and Gas was approximately $795 million. (See Note 1 to the Consolidated Financial Statements, "Summary of Significant Accounting Policies," for additional information.)

Insurance and Decommissioning

Duke Energy owns and operates the McGuire and Oconee Nuclear Stations and operates and has a partial ownership interest in the Catawba Nuclear Station. The McGuire and the Catawba Nuclear Stations have two nuclear reactors each and Oconee has three. Nuclear insurance includes: liability coverage; property, decontamination and premature decommissioning coverage; and business interruption and/or extra expense coverage. The other joint owners of the Catawba Nuclear Station reimburse Duke Energy for certain expenses associated with nuclear insurance premiums. The Price-Anderson Act requires Duke Energy to insure against public liability claims resulting from nuclear incidents to the full limit of liability, approximately $10.8 billion. (See Note 17 to the Consolidated Financial Statements, "Commitments and Contingencies—Nuclear Insurance," for more information.)

In 2005, the NCUC and PSCSC approved a $48 million annual amount for contributions and expense levels for decommissioning. During 2006, Duke Energy expensed approximately $48 million and contributed approximately $48 million of cash to the Nuclear Decommissioning Trust Funds (NDTF) for decommissioning costs; these amounts are presented in the Consolidated Statements of Cash Flows in Purchases of available-for-sale securities within Cash Flows from Investing Activities. The $48 million was contributed entirely to the funds reserved for contaminated costs. Contributions were discontinued to the funds reserved for non-contaminated costs since the current estimates indicate existing funds to be sufficient to cover projected future costs. The balance of the external funds was $1,775 million as of December 31, 2006 and $1,504 million as of December 31, 2005. These amounts are reflected in the Consolidated Balance Sheets as Nuclear Decommissioning Trust Funds (asset).

Estimated site-specific nuclear decommissioning costs, including the cost of decommissioning plant components not subject to radioactive contamination, total approximately $2.3 billion in 2003 dollars, based on a decommissioning study completed in 2004. This includes costs related to Duke Energy's 12.5% ownership in Catawba Nuclear Station. The other joint owners of Catawba Nuclear Station are responsible for decommissioning costs related to their ownership interests in the station. The previous study, conducted in 1999, estimated a decommissioning cost of $1.9 billion ($2.2 billion in 2003 dollars at 3% inflation). The estimated increase is due primarily to inflation and cost increases for the size of the organization needed to manage the decommissioning project (based on current industry experience at facilities undergoing decommissioning). Both the NCUC and the PSCSC have allowed Duke Energy to recover estimated decommissioning costs through retail rates over the expected remaining service periods of Duke Energy's nuclear stations. Management believes that the decommissioning costs being recovered through rates, when coupled with expected fund earnings, are sufficient to provide for the cost of decommissioning.

After spent fuel is removed from a nuclear reactor, it is cooled in a spent-fuel pool at the nuclear station. Under provisions of the Nuclear Waste Policy Act of 1982, Duke Energy contracted with the U.S. Department of Energy (DOE) for the disposal of spent nuclear fuel. The DOE failed to begin accepting spent nuclear fuel on January 31, 1998, the date specified by the Nuclear Waste Policy Act and in Duke Energy's contract with the DOE. In 1998, Duke Energy filed a claim with the U.S. Court of Federal Claims against the DOE related to the DOE's failure to accept commercial spent nuclear fuel by the required date. Damages claimed in the lawsuit are based upon Duke

Energy's costs incurred as a result of the DOE's partial material breach of its contract, including the cost of securing additional spent fuel storage capacity. The matter has been stayed pending the result of ongoing settlement negotiations between Duke Energy and the DOE. Duke Energy will continue to safely manage its spent nuclear fuel until the DOE accepts it. Payments made to the DOE for expected future disposal costs are based on nuclear output and are included in the Consolidated Statements of Operations as Fuel used in electric generation and purchased power. Duke Energy expects resolution of this matter in the first quarter of 2007.

Duke Energy has experienced numerous claims relating to damages for personal injuries alleged to have arisen from the exposure to or use of asbestos in connection with construction and maintenance activities conducted by Duke Energy Carolinas on its electric generation plants during the 1960s and 1970s. Duke Energy has third-party insurance to cover losses related to these asbestos-related injuries and damages above a certain aggregate deductible. The insurance policy, including the policy deductible and reserves, provided for coverage to Duke Energy up to an aggregate of $1.6 billion when purchased in 2000. Probable insurance recoveries related to this policy are classified in the Consolidated Balance Sheets as Other within Investments and Other Assets. Amounts recognized as reserves in the Consolidated Balance Sheets, which are not anticipated to exceed the coverage, are classified in Other Deferred Credits and Other Liabilities and Other Current Liabilities and are based upon Duke Energy's best estimate of the probable liability for future asbestos claims. These reserves are based upon current estimates and are subject to uncertainty. Factors such as the frequency and magnitude of future claims could change the current estimates of the related reserves and claims for recoveries reflected in the accompanying Consolidated Financial Statements. However, management of Duke Energy does not currently anticipate that any changes to these estimates will have any material adverse effect on Duke Energy's consolidated results of operations, cash flows or financial position.

Competition

U.S. Franchised Electric and Gas competes in some areas with government-owned power systems, municipally owned electric systems, rural electric cooperatives and other private utilities. By statute, the NCUC and the PSCSC assign service areas outside municipalities in North Carolina and South Carolina to regulated electric utilities and rural electric cooperatives. Substantially all of the territory comprising Duke Energy Carolinas' service area has been assigned in this manner. In unassigned areas, Duke Energy Carolinas' business remains subject to competition. A decision of the North Carolina Supreme Court limits, in some instances, the right of North Carolina municipalities to serve customers outside their corporate limits. In South Carolina, competition continues between municipalities and other electric suppliers outside the municipalities' corporate limits, subject to the regulation of the PSCSC. In Kentucky, the right of municipalities to serve customers outside corporate limits is subject to court approval. In Indiana, the state is divided into certified electric service areas for municipal utilities, rural cooperatives and investor owned utilities. There are limited circumstances where the certified electric service areas can be modified, with approval of the IURC. U.S. Franchised Electric and Gas also competes with other utilities and marketers in the wholesale electric business. In addition, U.S. Franchised Electric and Gas continues to compete with natural gas providers.

Duke Energy Ohio operates under the RSP Market Based Standard Service Offer (MBSSO) which was approved by the PUCO in November 2004, and which provides price certainty through December 31, 2008. In March 2005, the Office of the Ohio Consumers' Counsel (OCC) appealed the PUCO's approval of the MBSSO and in November 2006, the Ohio Supreme Court remanded the PUCO's order approving the MBSSO for further evidentiary support and explanation, and to require Duke Energy Ohio to disclose certain confidential commercial agreements between Duke Energy Ohio and other parties previously requested by the OCC. Hearings on remand are expected to occur in March 2007. A major feature of the MBSSO is the Provider of Last Resort (POLR) Charge. Duke Energy Ohio has been collecting a POLR charge from non-residential customers since January 1, 2005, and from residential customers since January 1, 2006. The POLR charge consists of the following discrete charges:

- Annually Adjusted Component – intended to provide cost recovery primarily for environmental compliance expenditures. This component is avoidable (or by-passable) for the first 25% of residential load and 50% of non-residential load to switch to an alternative electric service provider.

- Infrastructure Maintenance Fund Charge – intended to compensate Duke Energy Ohio for committing its physical capacity. This charge is unavoidable (or non-by-passable).

- System Reliability Tracker – intended to provide actual cost recovery for capacity purchases, purchased power, reserve capacity, and related market costs for purchases to meet capacity needs. This charge is non-by-passable for residential load and by-passable for non-residential load under certain circumstances.

- Rate Stabilization Charge – intended to compensate Duke Energy Ohio for maintaining a fixed price through 2008. This charge is by-passable by the first 25% of residential load and 50% of non-residential load to switch.

- Generation Prices and Fuel Recovery: A market price has been established for generation service. A component of the market price is a fuel cost recovery mechanism that is adjusted quarterly for fuel, emission allowances, and certain purchased power costs, that exceed the amount originally included in the rates frozen in the Duke Energy Ohio transition plan. These new prices were applied to non-residential customers beginning January 1, 2005 and to residential customers beginning January 1, 2006.

- Transmission Cost Recovery: A transmission cost recovery mechanism was established beginning January 1, 2005 for non-residential customers and beginning January 1, 2006 for residential customers. The transmission cost recovery mechanism is designed to permit Duke Energy Ohio to recover certain Midwest ISO charges, all FERC approved transmission costs, and all congestion costs allocable to retail ratepayers that are provided service by Duke Energy Ohio.

Regulation

State

The NCUC, the PSCSC, the PUCO, the IURC and the KPSC (collectively, the State Utility Commissions) approve rates for retail electric service within their respective ~~states. In addition, the PUCO and the KPSC approve rates for retail gas distribution service within their respective states. The FERC approves U.S. Franchised Electric and~~ Gas' cost based rates for electric sales to certain wholesale customers. (For more information on rate matters, see Note 4 to the Consolidated Financial Statements, "Regulatory Matters—U.S. Franchised Electric and Gas.") The FERC and the State Utility Commissions, except for the PUCO, also have authority over the construction and operation of U.S. Franchised Electric and Gas' facilities. Certificates of public convenience and necessity issued by the FERC and the State Utility Commissions, as applicable, authorize U.S. Franchised Electric and Gas to construct and operate its electric facilities, and to sell electricity to retail and wholesale customers. Prior approval from the relevant State Utility Commission is required for Duke Energy's regulated operating companies to issue securities.

Electric generation supply service has been deregulated in Ohio. Accordingly, Duke Energy Ohio's electric generation has been deregulated, and Duke Energy Ohio is in a competitive retail electric service market in the state of Ohio. Under applicable legislation governing the deregulation of generation, Duke Energy Ohio has implemented a RSP including a MBSSO approved by the PUCO. The RSP, among other things, allows Duke Energy Ohio to recover increased costs associated with environmental expenditures on its deregulated generating fleet, capacity reserves, and provides for a fuel and emission allowance cost recovery mechanism through 2008. (see Note 4 to the Consolidated Financial Statements, "Regulatory Matters—U.S. Franchised Electric and Gas Rate Related Information" for additional information.)

Federal

Regulations of FERC and the State Utility Commissions govern access to regulated electric and gas customer and other data by non-regulated entities, and services provided between regulated and non-regulated energy affiliates. These regulations affect the activities of non-regulated affiliates with U.S. Franchised Electric and Gas.

The Energy Policy Act of 2005 was signed into law in August 2005. The legislation directs specified agencies to conduct a significant number of studies on various aspects of the energy industry and to implement other provisions through rulemakings. Among the key provisions, the Energy Policy Act of 2005 repeals the Public Utility Holding Company Act (PUHCA) of 1935, directs FERC to establish a self-regulating electric reliability organization governed by an independent board with FERC oversight, extends the Price Anderson Act for 20 years (until 2025), provides loan guarantees, standby support and production tax credits for new nuclear reactors, gives FERC enhanced merger approval authority, provides FERC new backstop authority for the siting of certain electric transmission projects, streamlines the processes for approval and permitting of interstate pipelines, and reforms hydropower relicensing. In 2005 and 2006, FERC initiated several rulemakings as directed by the Energy Policy Act of 2005. These rule makings have now been completed, subject to certain appeals. Duke Energy does not believe that the appeals of these rulemakings will have a material adverse effect on its consolidated results of operations, cash flows or financial position.

The Energy Policy Act of 1992 and subsequent rulemakings and events initiated the opening of wholesale energy markets to competition. Open access transmission for wholesale transmission provides energy suppliers and load serving entities, including U.S. Franchised Electric and Gas and wholesale customers located in the U.S. Franchised Electric and Gas service area, with opportunities to purchase, sell and deliver capacity and energy at market based prices, which can lower overall costs to retail customers.

Duke Energy Ohio, Duke Energy Kentucky and Duke Energy Indiana are transmission owners in a regional transmission organization operated by the Midwest Independent Transmission System Operator, Inc. (Midwest ISO), a non-profit organization which maintains functional control over the combined transmission systems of its members. In 2005, the Midwest ISO began administering an energy market within its footprint.

As a result of previous FERC rulemakings related to RTOs, Duke Energy Carolinas and the franchised electric units of Carolina Power & Light Company (now Progress Energy Carolinas) and South Carolina Electric & Gas Company, planned to establish GridSouth Transco, LLC (GridSouth), as an RTO responsible for the functional control of the companies' combined transmission systems. As of December 31, 2006, Duke Energy Carolinas had a net investment of $41 million in GridSouth, including carrying costs calculated through December 31, 2002. This amount is included in Other Regulatory Assets and Deferred Debits on the Consolidated Balance Sheets. Due to regulatory uncertainty, development of the GridSouth implementation project was suspended in 2002. In 2005, the companies notified the FERC that they had discontinued the GridSouth project. Management expects it will recover its investment in GridSouth.

On December 17, 2001 the IURC approved the transfer of functional control of the operation of the Duke Energy Indiana transmission system to the Midwest ISO, an RTO established in 1998. On June 1, 2005, the IURC authorized Duke Energy Indiana to transfer control area operations tasks and responsibilities and transfer dispatch and Day 2 energy markets tasks and responsibilities to the Midwest ISO.

The Midwest ISO is the provider of transmission service requested on the transmission facilities under its tariff. It is responsible for the reliable operation of those transmission facilities and the regional planning of new transmission facilities. The Midwest ISO administers energy markets utilizing Locational Marginal Pricing (LMP) (i.e., the energy price for the next MW may vary throughout the Midwest ISO market based on transmission congestion and energy losses) as the methodology for relieving congestion on the transmission facilities under its functional control.

On December 19, 2005, the FERC approved a plan filed by Duke Energy Carolinas to establish an "Independent Entity" (IE) to serve as a coordinator of certain transmission functions and an "Independent Monitor" (IM) to monitor the transparency and fairness of the operation of Duke Energy Carolinas' transmission system. Under the proposal, Duke Energy Carolinas will remain the owner and operator of the transmission system with responsibility for the provision of transmission service under Duke Energy ~~Carolinas' Open Access Transmission Tariff. Duke Energy Carolinas has retained the Midwest ISO to act as the IE and Potomac Economics, Ltd. to act as the IM. The IE and~~ IM began operations on November 1, 2006. Duke Energy Carolinas is not at this time seeking adjustments to its transmission rates to reflect the incremental cost of the proposal, which is not projected to have a material adverse effect on Duke Energy's future consolidated results of operations, cash flows or financial position.

Other

U.S. Franchised Electric and Gas is subject to the NRC jurisdiction for the design, construction and operation of its nuclear generating facilities. In 2000, the NRC renewed the operating license for Duke Energy's three Oconee nuclear units through 2033 and 2034. In 2003, the NRC renewed the operating licenses for all units at Duke Energy's McGuire and Catawba stations. The two McGuire units are licensed through 2041 and 2043, while the two Catawba units are licensed through 2043. All but one of U.S. Franchised Electric and Gas' hydroelectric generating facilities are licensed by the FERC under Part I of the Federal Power Act, with license terms expiring from 2005 to 2036. The FERC has authority to issue new hydroelectric generating licenses. Hydroelectric facilities whose licenses have expired in 2005 are operating under annual extensions of the current license until FERC issues a new license. Other hydroelectric facilities whose licenses expire between 2008 and 2016 are in various stages of relicensing. Duke Energy expects to receive new licenses for all hydroelectric facilities with the exception of the Dillsboro Project, for which Duke Energy has filed an application to surrender the license. Duke Energy expects to remove this project's dam and powerhouse, as part of the multi-stakeholder licensing agreement.

U.S. Franchised Electric and Gas is subject to the jurisdiction of the EPA and state and local environmental agencies. (For a discussion of environmental regulation, see "Environmental Matters" in this section.)

NATURAL GAS TRANSMISSION

As previously discussed, effective January 2, 2007, Duke Energy consummated its spin-off of the natural gas transmission businesses (Spectra Energy), which includes the Natural Gas Transmission segment, to shareholders. The following business description of Natural Gas Transmission relates to 2006 and is not intended to describe the business subsequent to the spin-off on January 2, 2007.

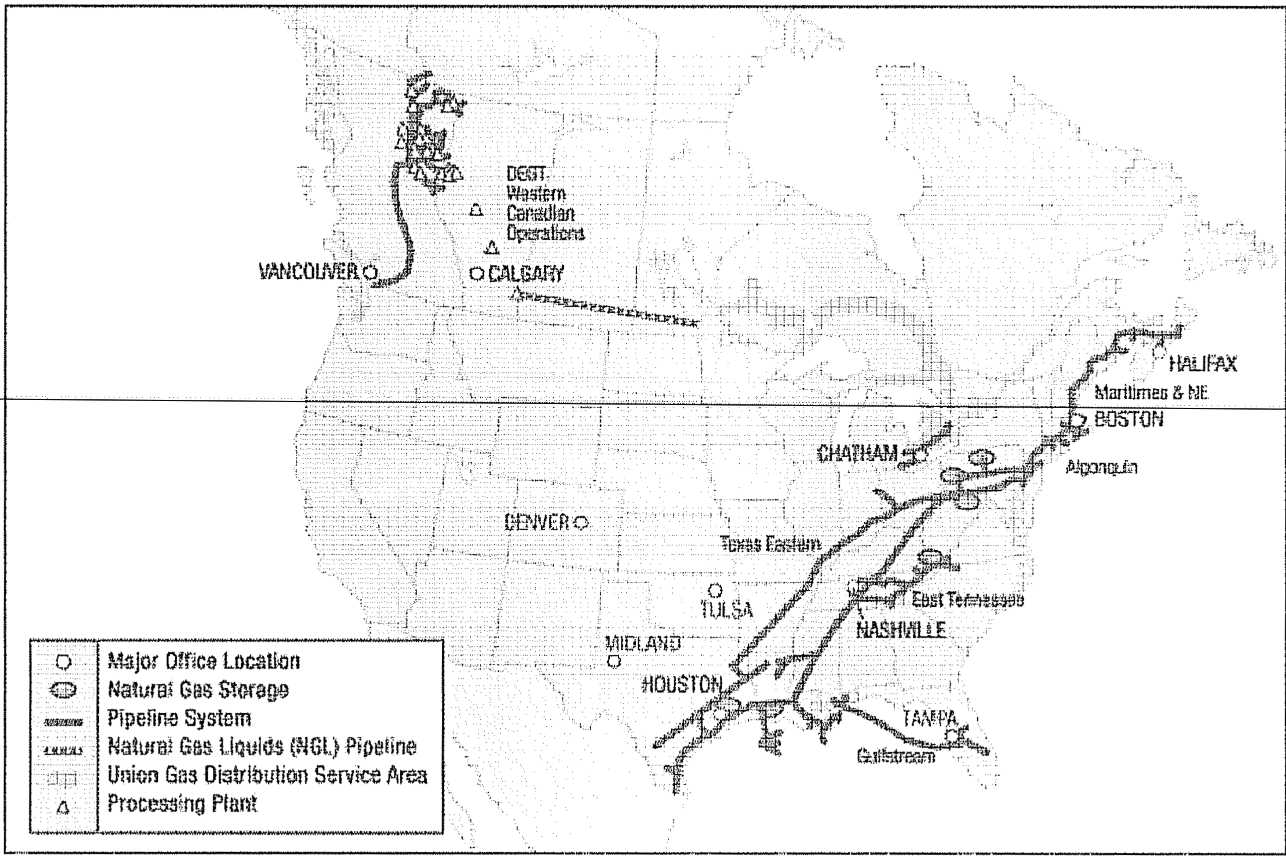
Natural Gas Transmission provides transportation and storage of natural gas for customers in various regions of the Eastern and Southeastern United States, the Maritimes Provinces and the Pacific Northwest in the United States and Canada and in the province of Ontario in Canada. Natural Gas Transmission also provides natural gas sales and distribution service to retail customers in Ontario, and natural gas gathering and processing services to customers in Western Canada. Natural Gas Transmission does business primarily through DEGT.

Natural Gas Transmission's pipeline systems consist of more than 17,500 miles of transmission pipelines. The pipeline systems receive natural gas from major North American producing regions for delivery to our markets. For 2006, Natural Gas Transmission's proportional throughput for its pipelines totaled 3,248 trillion British thermal units (TBtu), compared to 3,410 TBtu in 2005 This includes throughput on Natural Gas Transmission's wholly owned U.S. and Canadian pipelines and its proportional share of throughput on pipelines that are not wholly owned. A majority of Natural Gas Transmission's contracted transportation volumes are under long-term firm service agreements with LDC customers in the pipelines' market areas. Firm transportation services are also provided to gas marketers, producers, other pipelines, electric power generators and a variety of end-users, and both firm and interruptible transportation services are provided to various customers on a short-term or seasonal basis In the course of providing transportation services, Natural Gas Transmission also processes natural gas on its U.S system. Demand on Natural Gas Transmission's pipeline systems is seasonal, with the highest throughput occurring during colder periods in the first and fourth calendar quarters. (For detailed descriptions of Natural Gas Transmission's pipeline systems, see "Properties—*Natural Gas Transmission*")

Natural Gas Transmission, through Market Hub Partners (MHP), wholly owns natural gas salt cavern storage facilities in Southeast Texas and Louisiana. MHP markets natural gas storage services to pipelines, LDCs, producers, end users and natural gas marketers. Texas Eastern Transmission, L.P. (Texas Eastern) and East Tennessee Natural Gas, LLC (ETNG), subsidiaries of Natural Gas Transmission, also provide firm and interruptible open-access storage services. Storage is offered as a stand-alone unbundled service or as part of a no-notice bundled service with transportation. ETNG also connects to Saltville Gas Storage Company L.L.C. and Early Grove Storage Company, subsidiaries of Natural Gas Transmission. These underground reservoir and salt cavern storage facilities are located in Virginia and provide storage services to customers in the Southeastern United States

Natural Gas Transmission provides retail distribution services through its subsidiary, Union Gas Limited (Union Gas). Union Gas owns and operates natural gas transmission, distribution and storage facilities in Ontario. Union Gas distributes natural gas to approximately 1.3 million residential, commercial and industrial customers in Northern, Southwestern and Eastern Ontario and provides storage, transportation and related services to utilities and other industry participants in the gas markets of Ontario, Quebec and the Central and Eastern United States.

Natural Gas Transmission owns and operates gathering pipelines and gas processing plants in Western Canada through its British Columbia Pipeline System (BC Pipeline) operations and provides services primarily to natural gas producers to remove impurities from the raw gas stream including water, carbon dioxide, hydrogen sulphide and other substances. Where required, these facilities remove various NGLs. Natural Gas Transmission's Empress system assets located in Western Canada provide extraction, storage, transportation, distribution and marketing of NGLs in Canada and the U.S. Natural Gas Transmission also provides gathering and processing services through its 46% interest in the Canadian Midstream operations in Western Canada that are owned by Spectra Energy Income Fund (Income Fund), formerly Duke Energy Income Fund. Natural Gas Transmission continues to operate and manage this business



Competition

Natural Gas Transmission's transportation, storage and gas gathering and processing businesses compete with similar facilities that serve its supply and market areas in the transportation, storage, gathering and processing of natural gas. The principal elements of competition are rates, terms of service, flexibility and reliability of service.

Natural gas competes with other forms of energy available to Natural Gas Transmission's customers and end-users, including electricity, coal, propane and fuel oils. Several factors influence the demand for natural gas including price changes, the availability of natural gas and other forms of energy, the level of business activity, conservation, legislation, governmental regulations, the ability to convert to alternative fuels, weather and other factors.

Regulation

Most of Natural Gas Transmission's pipeline and storage operations in the U.S. are regulated by the FERC. The FERC regulates natural gas transportation in U.S. interstate commerce including the establishment of rates for services. (For more information on rate matters, see Note 4 to the Consolidated Financial Statements, "Regulatory Matters—Natural Gas Transmission.") The FERC also regulates the construction of U.S. interstate pipelines and storage facilities, including extension, enlargement or abandonment of such facilities. In addition, certain operations are subject to oversight by state regulatory commissions.

FERC regulations restrict U.S. interstate pipelines from sharing transmission or customer information with energy affiliates and require that U.S. interstate pipelines function independently of their energy affiliates. These regulations affect the activities of non-regulated affiliates with Natural Gas Transmission.

The FERC may propose and implement new rules and regulations affecting interstate natural gas transmission companies, which remain subject to the FERC's jurisdiction. These initiatives may also affect certain transportation of gas by intrastate pipelines.

Natural Gas Transmission's U.S. operations are subject to the jurisdiction of the EPA and state and local environmental agencies. (For a discussion of environmental regulation, see "Environmental Matters" in this section.) Natural Gas Transmission's interstate natural gas pipelines are also subject to the regulations of the DOT concerning pipeline safety.

The natural gas transmission, storage and distribution operations in Canada are subject to regulation by the NEB and provincial agencies in Canada, such as the OEB. These agencies have jurisdiction similar to the FERC for regulating rates, regulating the operations of facilities and construction of any additional facilities Natural Gas Transmission's federally regulated gathering and processing facilities and business in Western Canada is regulated by the NEB pursuant to a framework for light-handed regulation under which the NEB acts on a complaints basis for rates associated with that business. Similarly, the rates charged by the Midstream operation for gathering and processing services in Western Canada are regulated on a complaints basis by applicable provincial regulators. The Empress NGL businesses are not under any form of rate regulation.

FIELD SERVICES

As previously discussed, effective January 2, 2007, Duke Energy consummated the spin-off of the natural gas transmission businesses (Spectra Energy), including Duke Energy's investment in DEFS, to shareholders. The following business description of Field Services relates to 2006 and is not intended to describe the business subsequent to the spin-off on January 2, 2007.

Field Services includes Duke Energy's investment in DEFS, which gathers, compresses, processes, transports, trades and markets, and stores natural gas; and fractionates, transports, gathers, treats, processes, trades and markets, and stores NGLs. In July 2005, Duke Energy completed the disposition of its 19 7% interest in DEFS, which resulted in Duke Energy and ConocoPhillips becoming equal 50% owners in DEFS. The DEFS disposition transaction included the transfer to Duke Energy of DEFS' Canadian Midstream business. Additionally, the disposition transaction included the acquisition of ConocoPhillips' interest in the Empress System. Subsequent to the closing of the DEFS disposition transaction, effective on July 1, 2005, DEFS was no longer consolidated into Duke Energy's consolidated financial statements and is accounted for by Duke Energy as an equity method investment. The Canadian Midstream business and the Empress System have been transferred to the Natural Gas Transmission segment Additionally, in February 2005, DEFS sold its wholly-owned subsidiary, Texas Eastern Products Pipeline Company, LLC (TEPPCO GP), the general partner of TEPPCO Partners L P (TEPPCO LP), and Duke Energy sold its limited partner interest in TEPPCO LP., in each case to Enterprise GP Holdings LP (EPCO), an unrelated third party

In 2005, DEFS formed DCP Midstream Partners, LP (a master limited partnership) DCP Midstream Partners, LP (DCPLP) completed an IPO transaction in December 2005 As a result, DEFS has a 42 percent ownership interest in DCPLP, consisting of a 40 percent limited partner ownership interest and a 2 percent general partner ownership interest. DEFS owns 100 percent of the general partner of DCPLP.

DEFS operates in sixteen states in the United States (Alabama, Arkansas, Colorado, Kansas, Louisiana, Maine, Massachusetts, Mississippi, New Mexico, New York, Oklahoma, Pennsylvania, Texas, Rhode Island, Vermont and Wyoming). DEFS' gathering systems include connections to several interstate and intrastate natural gas and NGL pipeline systems and one natural gas storage facility. DEFS gathers raw natural gas through gathering systems located in seven major natural gas producing regions: Permian, Mid-Continent, East Texas-North Louisiana, South, Central, Rocky Mountain and Gulf Coast. DEFS owns or operates approximately 56,000 miles of gathering and transmission pipe, with approximately 34,000 active receipt points

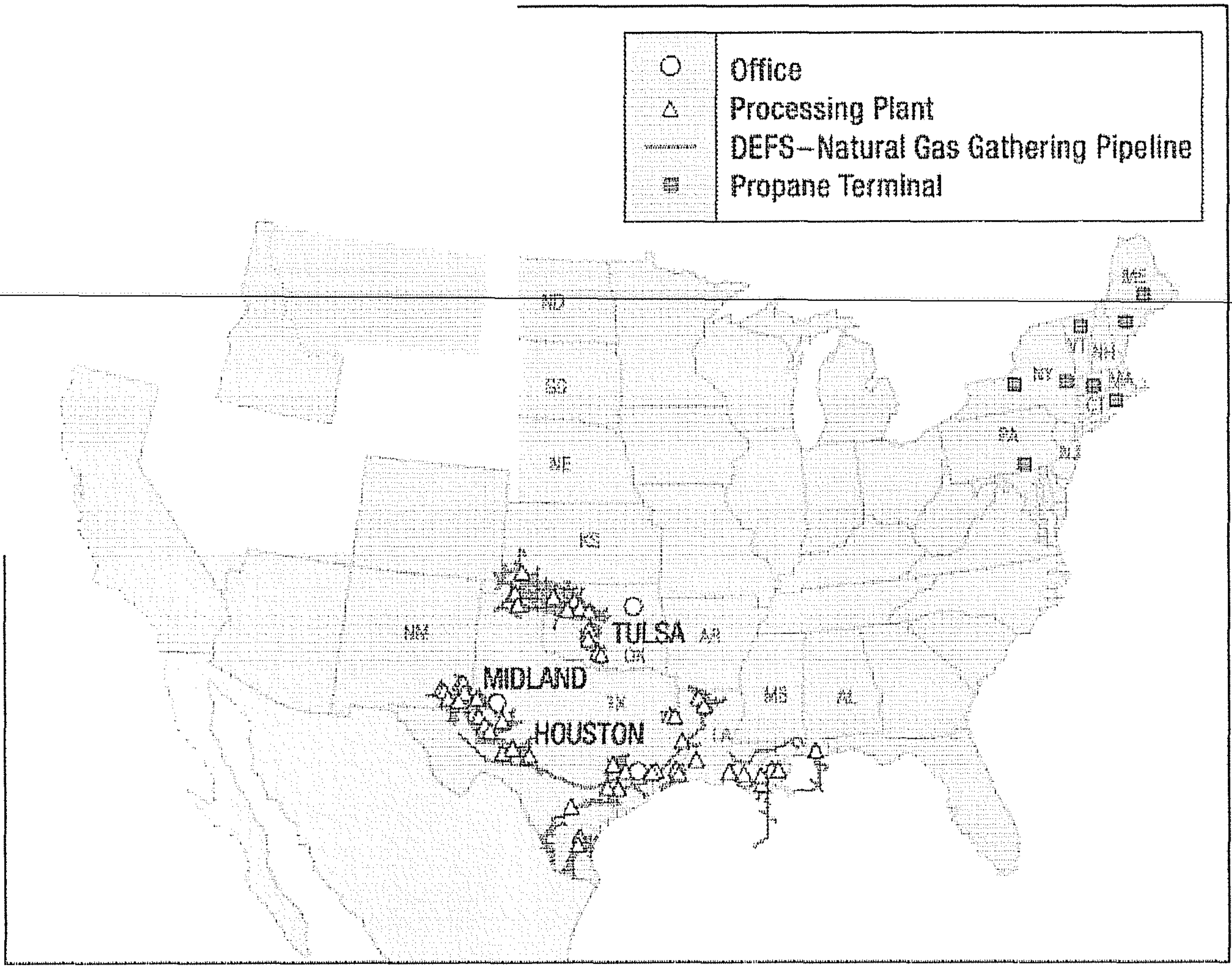
DEFS' natural gas processing operations separate raw natural gas that has been gathered on its own systems and third-party systems into condensate, NGLs and residue gas DEFS processes the raw natural gas at 53 natural gas processing facilities.

The NGLs separated from the raw natural gas are either sold and transported as NGL raw mix, or further separated through a fractionation process into their individual components (ethane, propane, butane and natural gasoline) and then sold as components DEFS fractionates NGL raw mix at six processing facilities that it owns and operates and at four third-party-operated facilities in which it has an ownership interest. In addition, DEFS operates a propane wholesale marketing business DEFS sells NGLs to a variety of customers ranging from large, multi-national petrochemical and refining companies to small, regional retail propane distributors. Substantially all of its NGL sales are at market-based prices

The residue gas separated from the raw natural gas is sold at market-based prices to marketers and end-users, including large industrial customers and natural gas and electric utilities serving individual consumers. DEFS markets residue gas directly or through its wholly owned gas marketing company and its affiliates. DEFS also stores residue gas at its 8 billion-cubic-foot (Bcf) natural gas storage facility.

DEFS uses NGL trading and storage at the Mont Belvieu, Texas and Conway, Kansas NGL market centers to manage its price risk and to provide additional services to its customers. Asset-based gas trading and marketing activities are supported by ownership of the Spindletop storage facility and various intrastate pipelines which provide access to market centers/hubs such as Katy, Texas, and the Houston Ship Channel. DEFS undertakes these NGL and gas trading activities through the use of fixed forward sales, basis and spread trades, storage opportunities, put/call options, term contracts and spot market trading DEFS believes there are additional opportunities to grow its services with its customer base.

The following map includes DEFS' natural gas gathering systems, intrastate pipelines, regional offices and supply areas.



DEFS' operating results are significantly impacted by changes in average NGL, natural gas and crude oil prices, which increased approximately 10%, decreased approximately 15% and increased approximately 15%, respectively, in 2006 compared to 2005. DEFS closely monitors the risks associated with these price changes, using NGL and crude forward contracts to mitigate the effect of such fluctuations on operating results. (See "Management's Discussion and Analysis of Financial Condition and Results of Operations, Quantitative and Qualitative Disclosures About Market Risk" for a discussion of DEFS' exposure to changes in commodity prices.)

Competition

In gathering and processing natural gas and in marketing and transporting natural gas and NGLs, DEFS competes with major integrated oil companies, major interstate and intrastate pipelines, national and local natural gas gatherers, and brokers, marketers and distributors of natural gas supplies. Competition for natural gas supplies is based primarily on the reputation, efficiency and reliability of operations, the availability of gathering and transportation to high-demand markets, the pricing arrangement offered by the gatherer/processor and the ability of the gatherer/processor to obtain a satisfactory price for the producer's residue gas and extracted NGLs. Competition for sales to customers is based primarily upon reliability, services offered, and price of delivered natural gas and NGLs.

Regulation

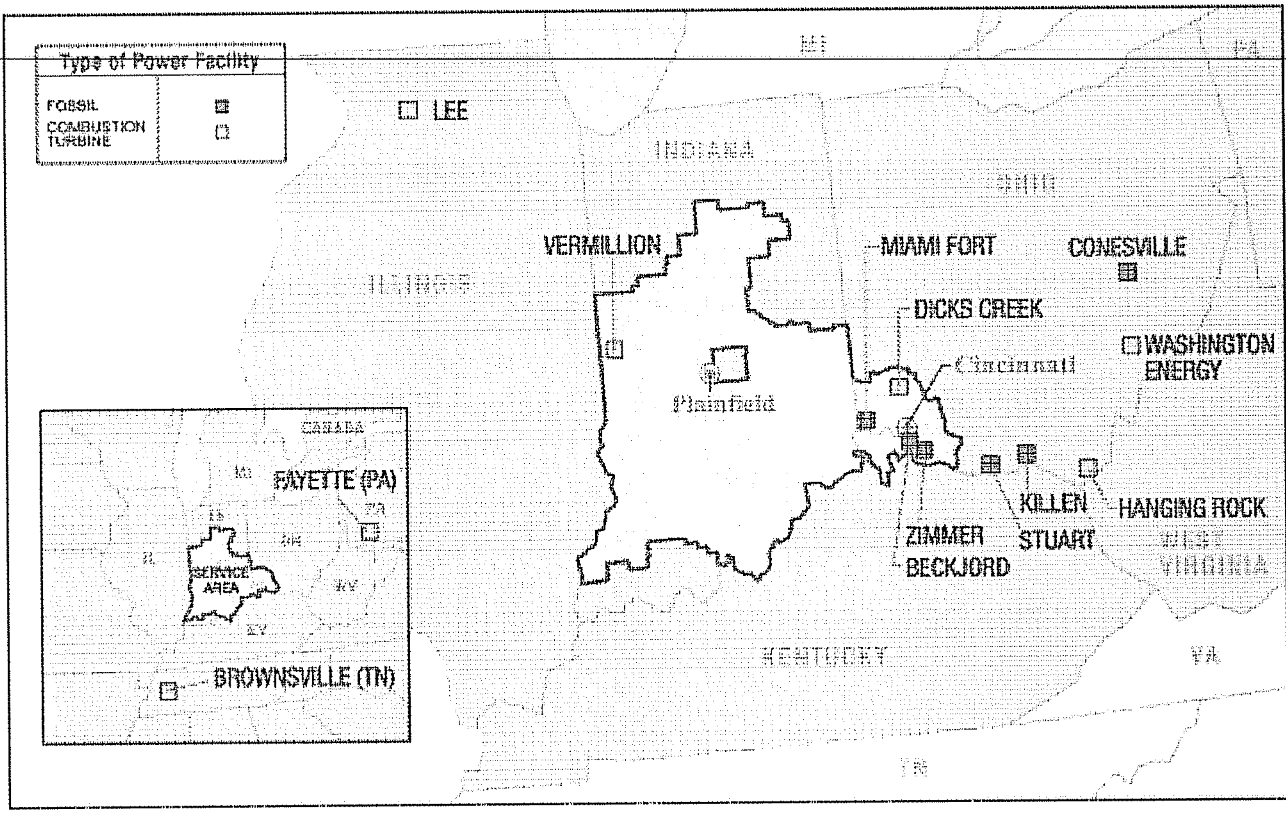
The intrastate natural gas and NGL pipelines owned by DEFS are subject to state regulation. To the extent that the natural gas intrastate pipelines provide services under Section 311 of the Natural Gas Policy Act of 1978, they are also subject to FERC regulation. The interstate natural gas pipeline owned and operated by DEFS is subject to FERC regulation, but its natural gas gathering and processing activities are not subject to FERC regulation.

DEFS is subject to the jurisdiction of the EPA and state and local environmental agencies. (For more information, see "Environmental Matters" in this section.) DEFS' natural gas transmission pipelines and some gathering pipelines are also subject to the regulations of the DOT, and in some cases, state agencies, concerning pipeline safety.

COMMERCIAL POWER

Commercial Power owns, operates and manages non-regulated merchant power plants and engages in the wholesale marketing and procurement of electric power, fuel and emission allowances related to these plants as well as other contractual positions. Commercial Power also develops and implements customized energy solutions Commercial Power's generation asset fleet consists of Duke Energy Ohio's non-regulated generation in Ohio, acquired from Cinergy in April 2006 and the five Midwestern gas-fired merchant generation assets that were a portion of former DENA. Commercial Power's assets are comprised of approximately 8,100 net megawatts of power generation primarily located in the Midwestern United States. The asset portfolio has a diversified fuel mix with base-load and mid-merit coal-fired units as well as combined cycle and peaking natural gas-fired units. Most of the generation asset output in Ohio has been contracted through the RSP described below. See Item 2. "Properties" for further discussion of the generating facilities.

Duke Energy – Midwest Power Generation
Non-Regulated Facilities



Commercial Power, through Duke Energy Generation Services (DEGS), is an on-site energy solutions and utility services provider. Primarily through joint ventures, DEGS engages in utility systems construction, operation and maintenance of utility facilities, as well as cogeneration. Cogeneration is the simultaneous production of two or more forms of usable energy from a single source. DEGS also owns coal-based synthetic fuel production facilities which convert coal feedstock into synthetic fuel for sale to third parties. The synthetic fuel produced in these facilities qualifies for tax credits through 2007 in accordance with Internal Revenue code Section 29/45K if certain requirements are satisfied.

In October 2006, Duke Energy completed the sale of Commercial Power's energy marketing and trading activities, which were acquired in the Cinergy merger. Additionally, in December 2006, Duke Energy completed the sale of Caledonia Power 1, LLC, which is the project company that operated and managed the Caledonia peaking generation facility in Mississippi.

Competition

Commercial Power primarily competes for wholesale contracts for the purchase and sale of electricity, coal, natural gas and emission allowances. The market price of commodities and services, along with the quality and reliability of services provided, drive competition in the energy marketing business. Commercial Power's main competitors include public utilities, wholesale power, coal and natural gas marketers and other merchant generation companies in the Midwestern United States, financial institutions and hedge funds engaged in energy commodity marketing and trading.

Duke Energy Ohio operates under the RSP MBSSO which was approved by the PUCO in November 2004, and which provides price certainty through December 31, 2008. In March 2005, the OCC appealed the PUCO's approval of the MBSSO and in November 2006, the Ohio Supreme Court remanded the PUCO's order approving the MBSSO for further evidentiary support and explanation, and to require Duke Energy Ohio to disclose certain confidential commercial agreements between Duke Energy Ohio and other parties previously requested by the OCC. Hearings on remand are expected to occur in March 2007. A major feature of the MBSSO is the POLR Charge. Duke Energy Ohio has been collecting a POLR charge from non-residential customers since January 1, 2005, and from residential customers since January 1, 2006. The POLR charge consists of the following discrete charges:

- Annually Adjusted Component – intended to provide cost recovery primarily for environmental compliance expenditures. This component is avoidable (or by-passable) for the first 25% of residential load and 50% of non-residential load to switch to an alternative electric service provider.

- Infrastructure Maintenance Fund Charge – intended to compensate Duke Energy Ohio for committing its physical capacity. This charge is unavoidable (or non-by-passable).

- System Reliability Tracker – intended to provide actual cost recovery for capacity purchases, purchased power, reserve capacity, and related market costs for purchases to meet capacity needs. This charge is non-by-passable for residential load and by-passable for non-residential load under certain circumstances.

- Rate Stabilization Charge – intended to compensate Duke Energy Ohio for maintaining a fixed price through 2008. This charge is by-passable by the first 25% of residential load and 50% of non-residential load to switch.

- Generation Prices and Fuel Recovery: A market price has been established for generation service. A component of the market price is a fuel cost recovery mechanism that is adjusted quarterly for fuel, emission allowances, and certain purchased power costs, that exceed the amount originally included in the rates frozen in the Duke Energy Ohio transition plan. These new prices were applied to non-residential customers beginning January 1, 2005 and to residential customers beginning January 1, 2006.

- Transmission Cost Recovery: A transmission cost recovery mechanism was established beginning January 1, 2005 for non-residential customers and beginning January 1, 2006 for residential customers. The transmission cost recovery mechanism is designed to permit Duke Energy Ohio to recover certain Midwest ISO charges, all FERC approved transmission costs, and all congestion costs allocable to retail ratepayers that are provided service by Duke Energy Ohio.

Regulation

Commercial Power is subject to regulation at the state level, primarily from PUCO and at the federal level, primarily from FERC. The PUCO approves prices for all retail electric generation sales by Duke Energy Ohio for its native retail service territory.

Regulations of FERC and the PUCO govern access to regulated electric customer and other data by non-regulated entities, and services provided between regulated and non-regulated energy affiliates. These regulations affect the activities of Commercial Power.

Other ongoing regulatory initiatives at both state and federal levels addressing market design, such as the development of capacity markets and real-time electricity markets, impact financial results from Commercial Power's marketing and generation activities.

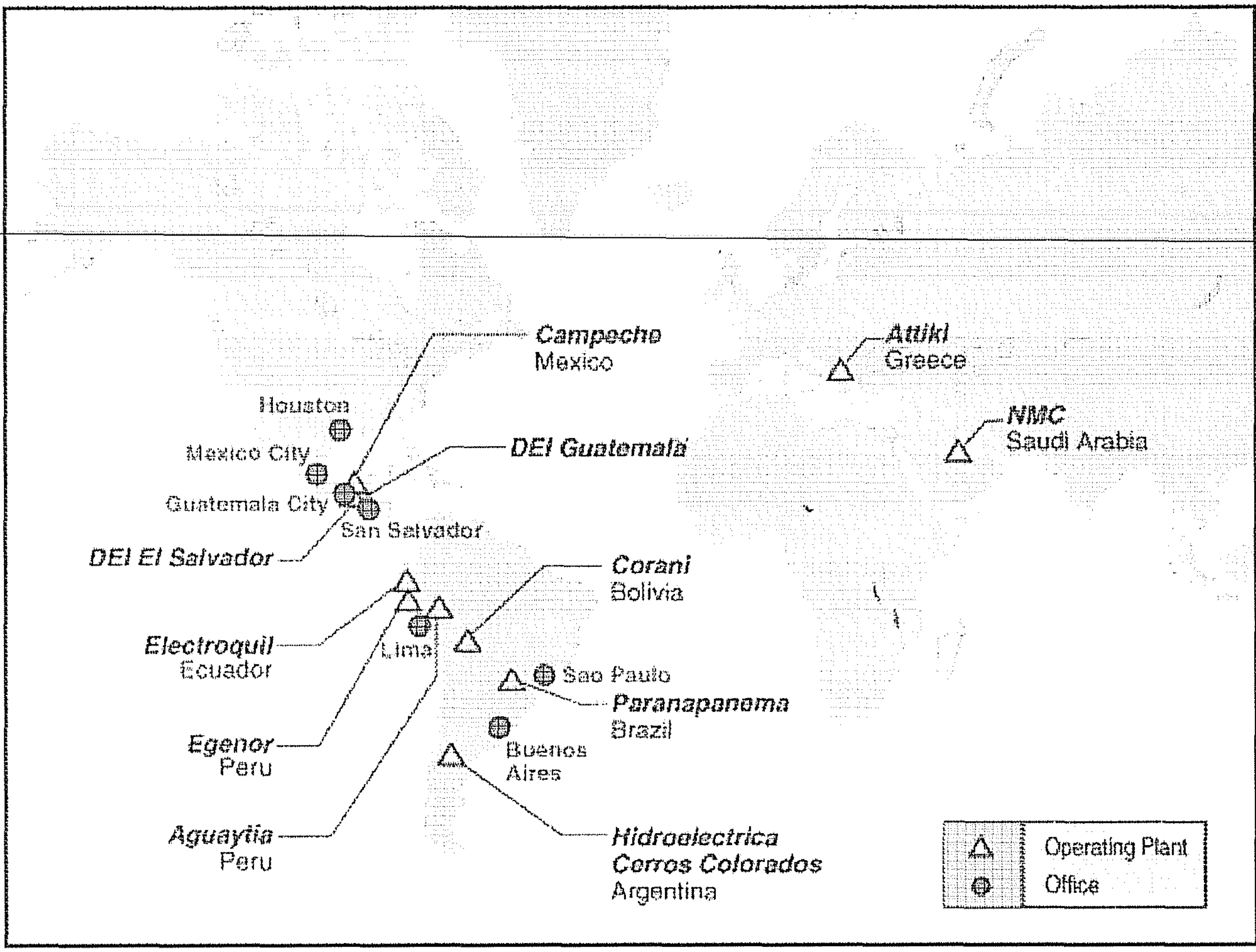
Commercial Power is subject to the jurisdiction of the EPA and state and local environmental agencies. (For a discussion of environmental regulation, see "Environmental Matters" in this section.)

INTERNATIONAL ENERGY

International Energy operates and manages power generation facilities and engages in sales and marketing of electric power and natural gas outside the U.S. and Canada. It conducts operations primarily through DEI and its activities target power generation in Latin America. Additionally, International Energy owns equity investments in: National Methanol Company (NMC), located in Saudi Arabia, which is a leading regional producer of methanol and methyl tertiary butyl ether (MTBE), Compania de Servicios de Compresion de Campeche, S.A. (Campeche), located in the Cantarell oil field in the Bay of Campeche, Mexico, which compresses and dehydrates natural gas and extracts NGL's, and Attiki Gas Supply S.A. (Attiki), located in Athens, Greece, which is a natural gas distributor and was acquired in connection with the Cinergy merger.

International Energy's customers include retail distributors, electric utilities, independent power producers, marketers and large industrial companies. International Energy's current strategy is focused on optimizing the value of its current Latin American portfolio.

International Energy owns, operates or has substantial interests in approximately 3,996 net MW of generation facilities. The following map shows the locations of International Energy's facilities, including non-generation facilities in Saudi Arabia, Mexico and Greece.



In December 2006, Duke Energy engaged in discussions with a potential buyer of International Energy's assets in Bolivia. Such discussions to sell the assets were subject to a binding agreement between the parties, which was finalized in February 2007, and resulted in the sale of International Energy's 50 percent ownership interest in two hydroelectric power plants near Cochabamba, Bolivia to Econergy International.

Competition and Regulation

International Energy's sales and marketing of electric power and natural gas competes directly with other generators and marketers serving its market areas. Competitors are country and region-specific but include government owned electric generating companies, LDCs with self-generation capability and other privately owned electric generating companies. The principal elements of competition are price and availability, terms of service, flexibility and reliability of service.

A high percentage of International Energy's portfolio consists of base-load hydro electric generation facilities which compete with other forms of electric generation available to International Energy's customers and end-users, including natural gas and fuel oils. Economic activity, conservation, legislation, governmental regulations, weather and other factors affect the supply and demand for electricity in the regions served by International Energy.

International Energy's operations are subject to both country-specific and international laws and regulations. (See "Environmental Matters" in this section.)

CRESCENT

As previously discussed, effective September 7, 2006, Duke Energy completed the Crescent JV transaction, whereby Duke Energy sold an effective 50% interest in Crescent

Crescent develops and manages high-quality commercial, residential and multi-family real estate projects, and manages land holdings, primarily in the Southeastern and Southwestern U.S. As of December 31, 2006, Crescent owned 1.1 million square feet of commercial, industrial and retail space, with an additional 0.3 million square feet under construction. This portfolio included 0.5 million square feet of office space, 0.5 million square feet of warehouse space and 0.4 million square feet of retail space. Crescent's residential developments include high-end country club and golf course communities, with individual lots sold to custom builders and tract developments sold to national builders. Crescent had three multi-family communities at December 31, 2006, including two operating properties and one property under development. As of December 31, 2006, Crescent also managed approximately 6,217 acres of land.

Competition and Regulation

Crescent competes with multiple regional and national real estate developers across its various business lines in the Southeastern and Southwestern U.S. Crescent's residential division sells developed lots to regional and national home builders and retail buyers, competing with other developers and home builders who have inventories of developed lots. Crescent's commercial division leases office, industrial and retail space, competing with other public and private developers and owners of commercial property, including national real estate investment trusts (REITs). Similarly, Crescent's multi-family division leases apartment units primarily to individuals, competing with other private developers and multi-family REITs.

Crescent is subject to the jurisdiction of the EPA and state and local environmental agencies. (For a discussion of environmental regulation, see "Environmental Matters" in this section.)

OTHER

The remainder of Duke Energy's operations is presented as "Other." While it is not considered a business segment, Other primarily includes the operations discussed below.

Other includes the remaining portion of Duke Energy's business formerly known as DENA, including its 100% owned affiliates Duke Energy Marketing America, LLC and Duke Energy Marketing Canada Corp. Duke Energy also participates in DETM. DETM is 40% owned by ExxonMobil Corporation and 60% owned by Duke Energy. During the third quarter of 2005, Duke Energy's Board of Directors authorized and directed management to execute the sale or disposition of substantially all of former DENA's remaining assets and contracts outside the Midwestern United States and certain contractual positions related to the Midwestern assets. Management retained former DENA's Midwestern generation assets (which are included in the Commercial Power segment), consisting of approximately 3,600 megawatts of power generation, and certain contracts related to the Midwestern generating facilities, as the merger with Cinergy provided a sustainable business model for those assets. The exit plan was completed in the second quarter of 2006.

The results of operations of former DENA's Western and Eastern United States generation assets, including related commodity contracts, the divested Ft. Frances generation assets, contracts related to former DENA's energy marketing and management activities and certain general and administrative costs, are required to be presented as discontinued operations classification for current and prior periods in the accompanying Consolidated Statements of Operations. In addition, the results for DETM will continue to be reported in continuing operations until the wind down of these operations is complete.

During 2006, Other also included certain unallocated corporate costs, certain discontinued hedges, DukeNet, Duke Energy's 50% interest in D/FD, Cinergy's equity financing business and Bison. Duke Energy had exited the merchant finance business at Duke Capital Partners LLC (DCP) as of the end of 2005 and all of the results of operations for DCP for the years ended December 31, 2005 and 2004 have been classified as discontinued operations.

DukeNet develops, owns and operates a fiber optic communications network, primarily in the Carolinas, serving wireless, local and long-distance communications companies, internet service providers and other businesses and organizations.

During 2003, Duke Energy determined that it would exit the refined products business at Duke Energy Merchants, LLC (DEM) in an orderly manner. As of December 31, 2006, DEM has completed the exit of its business. DEM previously engaged in commodity buying and selling, and risk management and financial services in non-regulated energy commodity markets other than physical natural gas and power (such as petroleum products). The results of operations for DEM have been classified as discontinued operations for all periods presented.

D/FD is a 50/50 partnership between subsidiaries of Duke Energy and Fluor. During 2003, Duke Energy and Fluor announced that they would dissolve D/FD, and adopted a plan for an orderly wind-down of D/FD's business. The wind-down has been substantially completed as of December 31, 2006. Previously, D/FD provided comprehensive engineering, procurement, construction, commissioning and operating plant services for fossil-fueled electric power generating facilities worldwide.

Cinergy has a business which invests in start up businesses utilizing new energy technologies as well as technologies utilizing energy infrastructure, such as broadband over power line services.

Bison's principal activities, as a captive insurance entity, include the insurance and reinsurance of various business risks and losses, such as workers compensation, property, business interruption, and general liability of subsidiaries and affiliates of Duke Energy. Bison also participates in reinsurance activities with certain third parties, on a limited basis.

Competition and Regulation

The entities within Other are subject to the jurisdiction of the EPA and state and local environmental agencies. (For a discussion of environmental regulation, see "Environmental Matters" in this section.)

ENVIRONMENTAL MATTERS

Duke Energy is subject to international, federal, state and local laws and regulations with regard to air and water quality, hazardous and solid waste disposal and other environmental matters. Environmental laws and regulations affecting Duke Energy include, but are not limited to:

- The Clean Air Act, as well as state laws and regulations impacting air emissions, including State Implementation Plans related to existing and new national ambient air quality standards for ozone and particulate matter. Owners and/or operators of air emission sources are responsible for obtaining permits and for annual compliance and reporting.
- The Clean Water Act which requires permits for facilities that discharge wastewaters into the environment.
- The Comprehensive Environmental Response, Compensation and Liability Act, which can require any individual or entity that currently owns or in the past may have owned or operated a disposal site, as well as transporters or generators of hazardous substances sent to a disposal site, to share in remediation costs.
- The Solid Waste Disposal Act, as amended by the Resource Conservation and Recovery Act, which requires certain solid wastes, including hazardous wastes, to be managed pursuant to a comprehensive regulatory regime.
- The National Environmental Policy Act, which requires federal agencies to consider potential environmental impacts in their decisions, including siting approvals.
- The North Carolina clean air legislation that freezes electric utility rates from June 20, 2002 to December 31, 2007 (rate freeze period), subject to certain conditions, in order for North Carolina electric utilities, including Duke Energy, to significantly reduce emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_x) from coal-fired power plants in the state. The legislation allows electric utilities, including Duke Energy, to accelerate the recovery of compliance costs by amortizing them over seven years (2003-2009).

(For more information on environmental matters involving Duke Energy, including possible liability and capital costs, see Notes 4 and 17 to the Consolidated Financial Statements, "Regulatory Matters," and "Commitments and Contingencies—Environmental," respectively.)

Except to the extent discussed in Note 4 to the Consolidated Financial Statements, "Regulatory Matters," and Note 17 to the Consolidated Financial Statements, "Commitments and Contingencies," compliance with international, federal, state and local provisions regulating the discharge of materials into the environment, or otherwise protecting the environment, is incorporated into the routine cost structure of our various business units and is not expected to have a material adverse effect on the competitive position, consolidated results of operations, cash flows or financial position of Duke Energy.

GEOGRAPHIC REGIONS

For a discussion of Duke Energy's foreign operations and the risks associated with them, see "Management's Discussion and Analysis of Results of Operations and Financial Condition, Quantitative and Qualitative Disclosures About Market Risk—Foreign Currency Risk," and Notes 3 and 8 to the Consolidated Financial Statements, "Business Segments" and "Risk Management and Hedging Activities, Credit Risk, and Financial Instruments," respectively.

EMPLOYEES

On December 31, 2006, Duke Energy had approximately 25,600 employees. A total of approximately 6,600 operating and maintenance employees were represented by unions.

EXECUTIVE OFFICERS OF DUKE ENERGY

HENRY B. BARRON JR., 56, Group Executive and Chief Nuclear Officer. Mr. Barron assumed his current position in November 2006. Prior to that, he served as Group Vice President, Nuclear Generation and Chief Nuclear Officer since April 2006, upon the merger of Duke Energy and Cinergy. Until the merger of Duke Energy and Cinergy, Mr. Barron served as Group Vice President, Nuclear Generation and Chief Nuclear Officer of Duke Energy since March 2004. Prior to that, he served as Executive Vice President, Nuclear Generation of Duke Energy from January 2004 to March 2004, Senior Vice President, Nuclear Operations of Duke Energy from September 2002 to January 2004 and Vice President, McGuire Nuclear Station of Duke Energy from March 1999 to September 2002.

LYNN J. GOOD, 47, Senior Vice President and Treasurer. Ms. Good assumed her current position in December 2006. Prior to that, she served as Vice President and Treasurer since April 2006, upon the merger of Duke Energy and Cinergy. Until the merger of Duke Energy and Cinergy, Ms. Good served as Executive Vice President and Chief Financial Officer of Cinergy from August 2005, Vice President, Finance and Controller of Cinergy from November 2003 to August 2005 and Vice President, Financial Project Strategy of Cinergy from May 2003 to November 2003. Prior to that, Ms. Good was a partner with the international accounting firm Deloitte & Touche LLP in Cincinnati, Ohio from May 2002 to May 2003. And, prior to that, she was a partner with the international accounting firm Arthur Anderson LLP from 1992 to May 2002.

DAVID L. HAUSER, 55, Group Executive and Chief Financial Officer. Mr. Hauser assumed his current position in April 2006, upon the merger of Duke Energy and Cinergy. Until the merger of Duke Energy and Cinergy, Mr. Hauser served as Group Vice President and Chief Financial Officer of Duke Energy since March 2004 and as Acting Chief Financial Officer of Duke Energy from December 2003 to March 2004. Prior to that, he served as Senior Vice President and Treasurer of Duke Energy from July 1998 to December 2003.

MARC E. MANLY, 54, Group Executive and Chief Legal Officer. Mr. Manly assumed his current position in April 2006, upon the merger of Duke Energy and Cinergy. Until the merger of Duke Energy and Cinergy, Mr. Manly served as Executive Vice President and Chief Legal Officer of Cinergy since November 2002. Prior to that, Mr. Manly served as Managing Director, Law and Governmental Affairs, General Counsel and Corporate Secretary of NewPower Holdings, Inc. from April 2000 to August 2002. On June 11, 2002, New Power Holdings, Inc. and its affiliates, TNPC Holdings, Inc. and the NewPower Company, filed a petition for relief under Chapter 11 of The United States Bankruptcy Code.

WILLIAM R. McCOLLUM JR, 55, Group Executive and Chief Regulated Generation Officer. Mr. McCollum assumed his current position in November 2006. Prior to that, he served as Group Vice President, Regulated Fossil/Hydro Generation since April 2006, upon the merger of Duke Energy and Cinergy. Until the merger of Duke Energy and Cinergy, Mr. McCollum served as Vice President, Strategy and Business Development for Duke Energy Carolinas since January 2005. Prior to that. Mr. McCollum served as Senior Vice President, Nuclear Support of Duke Energy from September 2002 to January 2005 and Vice Presdient, Oconee Nuclear Station of Duke Energy from March 1999 to September 2002.

THOMAS C. O'CONNOR, 51, Group Executive and President, Commercial Businesses. Mr. O'Connor assumed his current position in October 2006. Prior to that he served as Group Executive and Chief Operating Officer, U.S. Franchised Electric and Gas since April 2006, upon the merger of Duke Energy and Cinergy. Until the merger of Duke Energy and Cinergy, Mr. O'Connor served as President and Chief Executive Officer of Duke Energy Gas Transmission since December 2002. He has also served in leadership positions with Duke Energy's pipeline operations since 1994.

JAMES E. ROGERS, 59, Chairman, President and Chief Executive Officer. Mr. Rogers assumed the role of Chief Executive Officer and President in April 2006, upon the merger of Duke Energy and Cinergy and assumed the role of Chairman on January 2, 2007. Until the merger of Duke Energy and Cinergy, Mr. Rogers served as Chairman of the Board of Cinergy since 2000 and as Chief Executive Officer of Cinergy since 1995.

CHRISTOPHER C. ROLFE, 56, Group Executive and Chief Administrative Officer. Mr. Rolfe assumed his current position in November 2006. Prior to that, he served as Group Executive and Chief Human Resources Officer since April 2006, upon the merger of Duke Energy and Cinergy. Until the merger of Duke Energy and Cinergy, Mr. Rolfe served as Vice President, Human Resources of Duke Energy since January 2005. Prior to that, Mr. Rolfe served as Senior Vice President, Strategy, Planning & Human Resources of Duke Energy from March 2003 to January 2005 and Senior Vice President, Human Resources of Duke Energy from January 2001 to March 2003.

RUTH G. SHAW, 58, Executive Advisor to the Chairman, President and Chief Executive Officer. Dr. Shaw assumed her current position in October 2006. Prior to that she served as Group Executive, Public Policy and President, Duke Nuclear since April 2006, upon the merger of Duke Energy and Cinergy. Until the merger of Duke Energy and Cinergy, Dr. Shaw served as President and Chief Executive Officer, Duke Energy Carolinas since February 2003. Prior to that Dr. Shaw served as Executive Vice President and Chief Administrative Officer of Duke Energy Carolinas from 1997 to February 2003

B. KEITH TRENT, 47, Group Executive and Chief Strategy and Policy Officer. Mr. Trent assumed his current position in October 2006. Prior to that he served as Group Executive and Chief Development Officer since April 2006, upon the merger of Duke Energy and Cinergy. Until the merger of Duke Energy and Cinergy, Mr Trent served as Executive Vice President, General Counsel and Secretary of Duke Energy since March 2005. Prior to that he served as General Counsel, Litigation of Duke Energy from May 2002 to March 2005. Prior to that Mr. Trent served as a partner in the law firm Snell, Brannian & Trent since October 1991.

JAMES L. TURNER, 47, Group Executive and President, U.S. Franchised Electric and Gas. Mr. Turner assumed his current position in October 2006. Prior to that he served as Group Executive and Chief Commercial Officer, U.S. Franchised Electric and Gas since April 2006, upon the merger of Duke Energy and Cinergy. Until the merger of Duke Energy and Cinergy, Mr. Turner served as President of Cinergy since 2005, Executive Vice President and Chief Financial Officer of Cinergy from 2004 to 2005 and Executive Vice President and Chief Executive Officer, Regulated Business Unit of Cinergy from 2001 to 2004.

STEVEN K. YOUNG, 48, Senior Vice President and Controller. Mr. Young assumed his current position in December 2006. Prior to that he served as Vice President and Controller since April 2006, upon the merger of Duke Energy and Cinergy. Until the merger of Duke Energy and Cinergy, Mr. Young served as Vice President and Controller of Duke Energy since June 2005. Prior to that Mr. Young served as Senior Vice President and Chief Financial Officer of Duke Energy Carolinas from March 2003 to June 2005 and as Vice President, Rates and Regulatory Affairs of Duke Energy Carolinas from March 1998 to March 2003.

Executive officers are elected annually by the Board of Directors. They serve until the first meeting of the Board of Directors following the annual meeting of shareholders and until their successors are duly elected.

There are no family relationships between any of the executive officers, nor any arrangement or understanding between any executive officer and any other person involved in officer selection.

Item 1A. Risk Factors.

The risk factors discussed herein relate specifically to risks associated with Duke Energy subsequent to the spin-off of its natural gas businesses in January 2007. Accordingly, risks associated with the Spectra Energy businesses are not discussed in this section.

Duke Energy may be unable to achieve some or all of the benefits that are expected to be achieved in connection with the spin-off of its natural gas businesses in January 2007.

Duke Energy may not be able to achieve the full strategic and financial benefits that are expected to result from the spin-off transaction or such benefits may be delayed or may not occur at all

Duke Energy's franchised electric revenues, earnings and results are dependent on state legislation and regulation that affect electric generation, transmission, distribution and related activities, which may limit Duke Energy's ability to recover costs.

Duke Energy's franchised electric businesses are regulated on a cost-of-service/rate-of-return basis subject to the statutes and regulatory commission rules and procedures of North Carolina, South Carolina, Ohio, Indiana and Kentucky. If Duke Energy's franchised electric earnings exceed the returns established by the state regulatory commissions, Duke Energy's retail electric rates may be subject to review by the commissions and possible reduction, which may decrease Duke Energy's future earnings. Additionally, if regulatory bodies do not allow recovery of costs incurred in providing service on a timely basis, Duke Energy's future earnings could be negatively impacted.

Duke Energy may incur substantial costs and liabilities due to Duke Energy's ownership and operation of nuclear generating facilities.

Duke Energy's ownership interest in and operation of three nuclear stations subject Duke Energy to various risks including, among other things: the potential harmful effects on the environment and human health resulting from the operation of nuclear facilities and the storage, handling and disposal of radioactive materials; limitations on the amounts and types of insurance commercially available to cover losses that might arise in connection with nuclear operations; and uncertainties with respect to the technological and financial aspects of decommissioning nuclear plants at the end of their licensed lives.

Duke Energy's ownership and operation of nuclear generation facilities requires Duke Energy to meet licensing and safety-related requirements imposed by the NRC. In the event of non-compliance, the NRC may increase regulatory oversight, impose fines, and/or shut down a unit, depending upon its assessment of the severity of the situation. Revised security and safety requirements promulgated by the

NRC, which could be prompted by, among other things, events within or outside of Duke Energy's control, such as a serious nuclear incident at a facility owned by a third-party, could necessitate substantial capital and other expenditures at Duke Energy's nuclear plants, as well as assessments against Duke Energy to cover third-party losses. In addition, if a serious nuclear incident were to occur, it could have a material adverse effect on Duke Energy's results of operations and financial condition.

Duke Energy's ownership and operation of nuclear generation facilities also requires Duke Energy to maintain funded trusts that are intended to pay for the decommissioning costs of Duke Energy's nuclear power plants. Poor investment performance of these decommissioning trusts' holdings and other factors impacting decommissioning costs could unfavorably impact Duke Energy's liquidity and results of operations as Duke Energy could be required to significantly increase its cash contributions to the decommissioning trusts.

Duke Energy's plans for future expansion and modernization of its generation fleet subject it to risk of future price and inflationary increases in the cost of such expenditures as well as the risk of recovering such costs in a timely manner which could materially impact Duke Energy's financial condition, results of operations or cash flows.

During the three-year period from 2007 to 2009, Duke Energy anticipates annual capital expenditures of approximately $3 5 billion, for a total of approximately $10 billion. Duke Energy has begun to see significant increases in the estimated costs of these capital projects as a result of strong domestic and international demand for the material, equipment, and labor necessary to construct these facilities. Increases in costs related to materials and services required to expand and modernize Duke Energy's generation fleet as well as Duke Energy's ability to recover these costs in a timely manner could materially impact Duke Energy's consolidated financial condition, results of operations or cash flows.

Duke Energy's sales may decrease if Duke Energy is unable to gain adequate, reliable and affordable access to transmission assets.

Duke Energy depends on transmission and distribution facilities owned and operated by utilities and other energy companies to deliver the electricity Duke Energy sells to the wholesale market. FERC's power transmission regulations require wholesale electric transmission services to be offered on an open-access, non-discriminatory basis; however, not all markets are as open and accessible as needed. If transmission is disrupted, or if transmission capacity is inadequate, Duke Energy's ability to sell and deliver products may be hindered. Such disruptions could also hinder Duke Energy from providing electricity to Duke Energy's retail electric customers and may materially adversely affect Duke Energy's business.

The different regional power markets have changing regulatory structures, which could affect Duke Energy's growth and performance in these regions. In addition, the independent system operators who oversee the transmission systems in regional power markets have imposed in the past, and may impose in the future, price limitations and other mechanisms to address volatility in the power markets. These types of price limitations and other mechanisms may adversely impact the profitability of Duke Energy's wholesale power marketing and trading business

Duke Energy may be unable to secure long term power purchase agreements or transmission agreements, which could expose Duke Energy's sales to increased volatility.

In the future, Duke Energy may not be able to secure long-term power purchase agreements for Duke Energy's unregulated power generation facilities. If Duke Energy is unable to secure these types of agreements, Duke Energy's sales volumes would be exposed to increased volatility Without the benefit of long-term power purchase agreements, Duke Energy cannot assure that it will be able to sell the power generated by Duke Energy's facilities or that Duke Energy's facilities will be able to operate profitably. The inability to secure these agreements could materially adversely affect Duke Energy's results and business

Competition in the unregulated markets in which Duke Energy operates may adversely affect the growth and profitability of Duke Energy's business.

Duke Energy may not be able to respond in a timely or effective manner to the many changes designed to increase competition in the electricity industry. To the extent competitive pressures increase, the economics of Duke Energy's business may come under long-term pressure.

In addition, regulatory changes have been proposed to increase access to electricity transmission grids by utility and non-utility purchasers and sellers of electricity. These changes could continue the disaggregation of many vertically-integrated utilities into separate generation, transmission, distribution and retail businesses. As a result, a significant number of additional competitors could become active in the wholesale power generation segment of Duke Energy's industry.

Duke Energy may also face competition from new competitors that have greater financial resources than Duke Energy does, seeking attractive opportunities to acquire or develop energy assets or energy trading operations both in the United States and abroad. These new competitors may include sophisticated financial institutions, some of which are already entering the energy trading and marketing sector, and international energy players, which may enter regulated or unregulated energy businesses. This competition may adversely affect Duke Energy's ability to make investments or acquisitions.

Duke Energy must meet credit quality standards. If Duke Energy or its rated subsidiaries are unable to maintain an investment grade credit rating, Duke Energy would be required under credit agreements to provide collateral in the form of letters of credit or cash, which may materially adversely affect Duke Energy's liquidity. Duke Energy cannot be sure that it and its rated subsidiaries will maintain investment grade credit ratings.

Each of Duke Energy's and its rated subsidiaries senior unsecured long-term debt is rated investment grade by various rating agencies. Duke Energy cannot be sure that the senior unsecured long-term debt of Duke Energy or its rated subsidiaries will be rated investment grade.

If the rating agencies were to rate Duke Energy or its rated subsidiaries below investment grade, the entity's borrowing costs would increase, perhaps significantly. In addition, the entity would likely be required to pay a higher interest rate in future financings, and its potential pool of investors and funding sources would likely decrease. Further, if its short-term debt rating were to fall, the entity's access to the commercial paper market could be significantly limited. Any downgrade or other event negatively affecting the credit ratings of Duke Energy's subsidiaries could make their costs of borrowing higher or access to funding sources more limited, which in turn could increase Duke Energy's need to provide liquidity in the form of capital contributions or loans to such subsidiaries, thus reducing the liquidity and borrowing availability of the consolidated group.

A downgrade below investment grade could also trigger termination clauses in some interest rate and foreign exchange derivative agreements, which would require cash payments. All of these events would likely reduce Duke Energy's liquidity and profitability and could have a material adverse effect on Duke Energy's financial position, results of operations or cash flows.

Duke Energy relies on access to short-term money markets and longer-term capital markets to finance Duke Energy's capital requirements and support Duke Energy's liquidity needs, and Duke Energy's access to those markets can be adversely affected by a number of conditions, many of which are beyond Duke Energy's control.

Duke Energy's business is financed to a large degree through debt and the maturity and repayment profile of debt used to finance investments often does not correlate to cash flows from Duke Energy's assets. Accordingly, Duke Energy relies on access to both short-term money markets and longer-term capital markets as a source of liquidity for capital requirements not satisfied by the cash flow from Duke Energy's operations and to fund investments originally financed through debt instruments with disparate maturities. If Duke Energy is not able to access capital at competitive rates, Duke Energy's ability to finance Duke Energy's operations and implement Duke Energy's strategy will be adversely affected.

Market disruptions may increase Duke Energy's cost of borrowing or adversely affect Duke Energy's ability to access one or more financial markets. Such disruptions could include: economic downturns; the bankruptcy of an unrelated energy company; capital market conditions generally; market prices for electricity and gas; terrorist attacks or threatened attacks on Duke Energy's facilities or unrelated energy companies; or the overall health of the energy industry. Restrictions on Duke Energy's ability to access financial markets may also affect Duke Energy's ability to execute Duke Energy's business plan as scheduled. An inability to access capital may limit Duke Energy's ability to pursue improvements or acquisitions that Duke Energy may otherwise rely on for future growth.

Duke Energy maintains revolving credit facilities to provide back-up for commercial paper programs and/or letters of credit at various entities. These facilities typically include financial covenants which limit the amount of debt that can be outstanding as a percentage of the total capital for the specific entity. Failure to maintain these covenants at a particular entity could preclude that entity from issuing commercial paper or letters of credit or borrowing under the revolving credit facility and could require other of Duke Energy's affiliates to immediately pay down any outstanding drawn amounts under other revolving credit agreements.

Duke Energy's investments and projects located outside of the United States expose Duke Energy to risks related to laws of other countries, taxes, economic conditions, political conditions and policies of foreign governments. These risks may delay or reduce Duke Energy's realization of value from Duke Energy's international projects.

Duke Energy currently owns and may acquire and/or dispose of material energy-related investments and projects outside the United States. The economic, regulatory, market and political conditions in some of the countries where Duke Energy has interests or in which

Duke Energy may explore development, acquisition or investment opportunities could present risks related to, among others, Duke Energy's ability to obtain financing on suitable terms, Duke Energy's customers' ability to honor their obligations with respect to projects and investments, delays in construction, limitations on Duke Energy's ability to enforce legal rights, and interruption of business, as well as risks of war, expropriation, nationalization, renegotiation, trade sanctions or nullification of existing contracts and changes in law, regulations, market rules or tax policy.

Duke Energy's investments and projects located outside of the United States expose Duke Energy to risks related to fluctuations in currency rates. These risks, and Duke Energy's activities to mitigate such risks, may adversely affect Duke Energy's cash flows and results of operations.

Duke Energy's operations and investments outside the United States expose Duke Energy to risks related to fluctuations in currency rates. As each local currency's value changes relative to the U.S. dollar—Duke Energy's principal reporting currency—the value in U.S. dollars of Duke Energy's assets and liabilities in such locality and the cash flows generated in such locality, expressed in U.S. dollars, also change.

Duke Energy selectively mitigates some risks associated with foreign currency fluctuations by, among other things, indexing contracts to the U.S. dollar and/or local inflation rates, hedging through debt denominated or issued in the foreign currency and hedging through foreign currency derivatives. These efforts, however, may not be effective and, in some cases, may expose Duke Energy to other risks that could negatively affect Duke Energy's cash flows and results of operations.

~~Duke Energy's primary foreign currency rate exposure is expected to be to the Brazilian Real.~~ A 10% devaluation in the currency exchange rate in all of Duke Energy's exposure currencies would result in an estimated net loss on the translation of local currency earnings of approximately $7 million. The consolidated balance sheets would be negatively impacted by such a devaluation by approximately $120 million through cumulative currency translation adjustments.

Duke Energy is exposed to credit risk of counterparties with whom Duke Energy does business.

Adverse economic conditions affecting, or financial difficulties of, counterparties with whom Duke Energy does business could impair the ability of these counterparties to pay for Duke Energy's services or fulfill their contractual obligations, or cause them to delay such payments or obligations. Duke Energy depends on these counterparties to remit payments on a timely basis. Any delay or default in payment could adversely affect Duke Energy's cash flows, financial position or results of operations

Poor investment performance of pension plan holdings and other factors impacting pension plan costs could unfavorably impact Duke Energy's liquidity and results of operations.

Duke Energy's costs of providing non-contributory defined benefit pension plans are dependent upon a number of factors, such as the rates of return on plan assets, discount rates, the level of interest rates used to measure the required minimum funding levels of the plans, future government regulation and Duke Energy's required or voluntary contributions made to the plans. While Duke Energy complies with the minimum funding requirements as of September 30, 2006, Duke Energy has certain qualified U.S. pension plans with obligations which exceeded the value of plan assets by approximately $500 million. Without sustained growth in the pension investments over time to increase the value of Duke Energy's plan assets and depending upon the other factors impacting Duke Energy's costs as listed above, Duke Energy could be required to fund its plans with significant amounts of cash. Such cash funding obligations could have a material impact on Duke Energy's cash flows, financial position or results of operations.

Duke Energy is subject to numerous environmental laws and regulations that require significant capital expenditures, can increase Duke Energy's cost of operations, and which may impact or limit Duke Energy's business plans, or expose Duke Energy to environmental liabilities.

Duke Energy is subject to numerous environmental laws and regulations affecting many aspects of Duke Energy's present and future operations, including air emissions (such as reducing NO_x, SO_2 and mercury emissions in the U.S., or potential future control of greenhouse-gas emissions), water quality, wastewater discharges, solid waste and hazardous waste. These laws and regulations can result in increased capital, operating, and other costs. These laws and regulations generally require Duke Energy to obtain and comply with a wide variety of environmental licenses, permits, inspections and other approvals. Compliance with environmental laws and regulations can require significant expenditures, including expenditures for clean up costs and damages arising out of contaminated properties, and failure to comply with environmental regulations may result in the imposition of fines, penalties and injunctive measures affecting operating assets. The steps Duke Energy takes to ensure that its facilities are in compliance could be prohibitively expensive. As a result, Duke Energy may be required to shut down or alter the operation of its facilities, which may cause Duke Energy to incur losses. Further, Duke Energy's regulatory rate structure and Duke Energy's contracts with customers may not necessarily allow Duke Energy to recover capital costs Duke Energy incurs to comply with new environmental regulations. Also, Duke Energy may not be able to obtain or maintain from time to time all required environmental regulatory approvals for Duke Energy's operating assets or development projects. If there is a delay in obtaining any required environmental regulatory approvals, if Duke Energy fails to obtain and comply with them or if environmental laws or regulations change and become more stringent, then the operation of Duke Energy's facilities or the development of new facilities could be prevented, delayed or become subject to additional costs. Although it is not expected that the costs of complying with current environmental regulations will have a material adverse effect on Duke Energy's cash flows, financial position or results of operations, no assurance can be made that the costs of complying with environmental regulations in the future will not have such an effect.

There is growing consensus that some form of regulation will be forthcoming at the federal level with respect to greenhouse gas emissions (including CO_2) and such regulation could result in the creation of substantial additional costs in the form of taxes or emission allowances.

In addition, Duke Energy is generally responsible for on-site liabilities, and in some cases off-site liabilities, associated with the environmental condition of Duke Energy's power generation facilities and natural gas assets which Duke Energy has acquired or developed, regardless of when the liabilities arose and whether they are known or unknown. In connection with some acquisitions and sales of assets, Duke Energy may obtain, or be required to provide, indemnification against some environmental liabilities. If Duke Energy incurs a material liability, or the other party to a transaction fails to meet its indemnification obligations to Duke Energy, Duke Energy could suffer material losses.

Deregulation or restructuring in the electric industry may result in increased competition and unrecovered costs that could adversely affect Duke Energy's financial condition, results of operations or cash flows and Duke Energy's utilities' businesses.

Increased competition resulting from deregulation or restructuring efforts, including from the Energy Policy Act of 2005, could have a significant adverse financial impact on Duke Energy and Duke Energy's utility subsidiaries and consequently on Duke Energy's results of operations, financial position, or cash flows. Increased competition could also result in increased pressure to lower costs, including the cost of electricity. Retail competition and the unbundling of regulated energy and gas service could have a significant adverse financial impact on Duke Energy and Duke Energy's subsidiaries due to an impairment of assets, a loss of retail customers, lower profit margins or increased costs of capital. Duke Energy cannot predict the extent and timing of entry by additional competitors into the electric markets. Duke Energy cannot predict when Duke Energy will be subject to changes in legislation or regulation, nor can Duke Energy predict the impact of these changes on its financial position, results of operations or cash flows.

Duke Energy is involved in numerous legal proceedings, the outcome of which are uncertain, and resolution adverse to Duke Energy could negatively affect Duke Energy's cash flows, financial condition or results of operations.

Duke Energy is subject to numerous legal proceedings. Litigation is subject to many uncertainties and Duke Energy cannot predict the outcome of individual matters with assurance. It is reasonably possible that the final resolution of some of the matters in which Duke Energy is involved could require Duke Energy to make additional expenditures, in excess of established reserves, over an extended period of time and in a range of amounts that could have a material effect on Duke Energy's cash flows and results of operations. Similarly, it is reasonably possible that the terms of resolution could require Duke Energy to change Duke Energy's business practices and procedures, which could also have a material effect on Duke Energy's cash flows, financial position or results of operations.

Duke Energy's results of operations may be negatively affected by sustained downturns or sluggishness in the economy, including low levels in the market prices of commodities, all of which are beyond Duke Energy's control.

Sustained downturns or sluggishness in the economy generally affect the markets in which Duke Energy operates and negatively influence Duke Energy's energy operations. Declines in demand for electricity as a result of economic downturns in Duke Energy's franchised electric service territories will reduce overall electricity sales and lessen Duke Energy's cash flows, especially as Duke Energy's industrial customers reduce production and, therefore, consumption of electricity and gas. Although Duke Energy's franchised electric business is subject to regulated allowable rates of return and recovery of fuel costs under a fuel adjustment clause, overall declines in electricity sold as a result of economic downturn or recession could reduce revenues and cash flows, thus diminishing results of operations.

Duke Energy also sells electricity into the spot market or other competitive power markets on a contractual basis. With respect to such transactions, Duke Energy is not guaranteed any rate of return on Duke Energy's capital investments through mandated rates, and Duke Energy's revenues and results of operations are likely to depend, in large part, upon prevailing market prices in Duke Energy's regional markets and other competitive markets. These market prices may fluctuate substantially over relatively short periods of time and could reduce Duke Energy's revenues and margins and thereby diminish Duke Energy's results of operations.

Lower demand for the electricity Duke Energy sells and lower prices for electricity result from multiple factors that affect the markets where Duke Energy sells electricity including:

- weather conditions, including abnormally mild winter or summer weather that cause lower energy usage for heating or cooling purposes, respectively, and periods of low rainfall that decrease Duke Energy's ability to generate hydroelectric energy;
- supply of and demand for energy commodities;
- illiquid markets including reductions in trading volumes which result in lower revenues and earnings;
- general economic conditions, including downturns in the U.S. or other economies which impact energy consumption particularly in which sales to industrial or large commercial customers comprise a significant portion of total sales;
- transmission or transportation constraints or inefficiencies which impact Duke Energy's merchant energy operations;
- availability of competitively priced alternative energy sources, which are preferred by some customers over electricity produced from coal, nuclear or gas plants, and of ~~energy-efficient equipment which reduces energy demand;~~
- natural gas, crude oil and refined products production levels and prices;
- ability to procure satisfactory levels of inventory, such as coal;
- electric generation capacity surpluses which cause Duke Energy's merchant energy plants to generate and sell less electricity at lower prices and may cause some plants to become non-economical to operate;
- capacity and transmission service into, or out of, Duke Energy's markets;
- natural disasters, acts of terrorism, wars, embargoes and other catastrophic events to the extent they affect Duke Energy's operations and markets, as well as the cost and availability of insurance covering such risks; and
- federal, state and foreign energy and environmental regulation and legislation.

These factors have led to industry-wide downturns that have resulted in the slowing down or stopping of construction of new power plants and announcements by Duke Energy and other energy suppliers and gas pipeline companies of plans to sell non-strategic assets, subject to regulatory constraints, in order to boost liquidity or strengthen balance sheets. Proposed sales by other energy suppliers could increase the supply of the types of assets that Duke Energy is attempting to sell. In addition, recent FERC actions addressing power market concerns could negatively impact the marketability of Duke Energy's electric generation assets.

Duke Energy's operating results may fluctuate on a seasonal and quarterly basis.

Electric power generation is generally a seasonal business. In most parts of the United States and other markets in which Duke Energy operates, demand for power peaks during the hot summer months, with market prices also peaking at that time. In other areas, demand for power peaks during the winter. Further, extreme weather conditions such as heat waves or winter storms could cause these seasonal fluctuations to be more pronounced. As a result, in the future, the overall operating results of Duke Energy's businesses may fluctuate substantially on a seasonal and quarterly basis and thus make period comparison less relevant.

Duke Energy's business is subject to extensive regulation that will affect Duke Energy's operations and costs.

Duke Energy is subject to regulation by FERC and the NRC, by federal, state and local authorities under environmental laws and by state public utility commissions under laws regulating Duke Energy's businesses. Regulation affects almost every aspect of Duke Energy's businesses, including, among other things, Duke Energy's ability to: take fundamental business management actions; determine the terms and rates of Duke Energy's transmission and distribution businesses' services; make acquisitions; issue equity or debt securities; engage in transactions between Duke Energy's utilities and other subsidiaries and affiliates; and pay dividends. Changes to these regulations are ongoing, and Duke Energy cannot predict the future course of changes in this regulatory environment or the ultimate effect that this changing regulatory environment will have on Duke Energy's business. However, changes in regulation (including re-regulating previously deregulated markets) can cause delays in or affect business planning and transactions and can substantially increase Duke Energy's costs.

FERC has established certain market screens it employs to assess generation market power. Certain of these screens are difficult for a franchised utility to pass. In an order issued on June 30, 2005 the FERC revoked the authority for Duke Energy Carolinas to make wholesale power sales within its control area at market-based rates based on the FERC's determination that Duke Energy Carolinas failed one of the applicable market screens. Under the FERC's order, Duke Energy Carolinas must pay partial refunds and may prospectively make wholesale power sales within its control area only at cost-based rates.

Certain events in the energy markets beyond Duke Energy's control have increased the level of public and regulatory scrutiny in the energy industry and in the capital markets and could result in new laws or regulations which could have a negative impact on Duke Energy's results of operations.

Due to certain events in the energy markets, regulated energy companies have been under increased scrutiny by regulatory bodies, capital markets and credit rating agencies. This increased scrutiny could lead to substantial changes in laws and regulations affecting Duke Energy, including new accounting standards that could change the way Duke Energy is required to record revenues, expenses, assets and liabilities. These types of regulations could have a negative impact on Duke Energy's financial position, cash flows or results of operations or access to capital.

Potential terrorist activities or military or other actions could adversely affect Duke Energy's business.

The continued threat of terrorism and the impact of retaliatory military and other action by the United States and its allies may lead to increased political, economic and financial market instability and volatility in prices for natural gas and oil which may materially adversely affect Duke Energy in ways Duke Energy cannot predict at this time. In addition, future acts of terrorism and any possible reprisals as a consequence of action by the United States and its allies could be directed against companies operating in the United States. Infrastructure and generation facilities such as Duke Energy's nuclear plants could be potential targets of terrorist activities. The potential for terrorism has subjected Duke Energy's operations to increased risks and could have a material adverse effect on Duke Energy's business. In particular, Duke Energy may experience increased capital and operating costs to implement increased security for its plants, including its nuclear power plants under the NRC's design basis threat requirements, such as additional physical plant security, additional security personnel or additional capability following a terrorist incident.

The insurance industry has also been disrupted by these events. As a result, the availability of insurance covering risks Duke Energy and Duke Energy's competitors typically insure against may decrease. In addition, the insurance Duke Energy is able to obtain may have higher deductibles, higher premiums and more restrictive policy terms.

Item 1B. Unresolved Staff Comments.

None.

Item 2. Properties.

U.S. FRANCHISED ELECTRIC AND GAS

As of December 31, 2006, U.S. Franchised Electric and Gas operated three nuclear generating stations with a combined net capacity of 5,020 MW (including a 12.5% ownership in the Catawba Nuclear Station), fifteen coal-fired stations with a combined net capacity of 13,552 MW, thirty-one hydroelectric stations (including two pumped-storage facilities) with a combined net capacity of 3,213 MW, fifteen CT stations with a combined net capacity of 5,245 MW and two CC stations with a combined net capacity of 560 MW. The stations are located in North Carolina, South Carolina, Indiana, Ohio and Kentucky. The MW displayed in the table below are based on summer capacity.

Name	Gross MW	Net MW	Fuel	Location	Ownership Interest (percentage)
Carolinas:					
Oconee	2,538	2,538	Nuclear	SC	100 %
Catawba	2,258	282	Nuclear	SC	12.5
Belews Creek	2,270	2,270	Coal	NC	100
McGuire	2,200	2,200	Nuclear	NC	100
Marshall	2,110	2,110	Coal	NC	100
Lincoln CT	1,267	1,267	Natural gas/Fuel oil	NC	100
Allen	1,145	1,145	Coal	NC	100
Bad Creek	1,360	1,360	Hydro	SC	100
Rockingham CT	825	825	Natural gas/Fuel oil	NC	100
Cliffside	760	760	Coal	NC	100
Jocassee	680	680	Hydro	SC	100
Riverbend	454	454	Coal	NC	100
Lee	370	370	Coal	SC	100
Buck	369	369	Coal	NC	100
Cowans Ford	325	325	Hydro	NC	100
Mill Creek CT	596	596	Natural gas/Fuel oil	SC	100
Dan River	276	276	Coal	NC	100
Buzzard Roost CT	196	196	Natural gas/Fuel oil	SC	100
Keowee	152	152	Hydro	SC	100
Riverbend CT	120	120	Natural gas/Fuel oil	NC	100
Buck CT	93	93	Natural gas/Fuel oil	NC	100
Lee CT	84	84	Natural gas/Fuel oil	SC	100
Dan River CT	85	85	Natural gas/Fuel oil	NC	100
Other small hydro (27 plants)	651	651	Hydro	NC/SC	100
Midwest:					
Gibson(A)	3,132	2,820	Coal	IN	100
Cayuga(B)	1,005	1,005	Coal/Fuel oil	IN	100
Wabash River(C)	676	676	Coal/Fuel oil	IN	100
East Bend	600	414	Coal	KY	69
Madison CT	596	596	Natural gas	OH	100
Gallagher	560	560	Coal	IN	100
Woodsdale CT	500	500	Natural gas/Propane	OH	100
Wheatland CT	460	460	Natural gas	IN	100
Noblesville CC	285	285	Natural gas	IN	100
Wabash River CC(D)	275	275	Syn Gas/Natural gas	IN	100
Miami Fort (Units 5 and 6)	163	163	Coal/Fuel oil	OH	100
Edwardsport	160	160	Coal	IN	100
Henry County CT	135	135	Natural gas	IN	100
Cayuga CT	106	106	Natural gas	IN	100
Miami Wabash CT	96	96	Fuel oil	IN	100
Connersville CT	86	86	Fuel oil	IN	100
Markland	45	45	Hydro	IN	100
Total	30,064	27,590			

(A) Duke Energy Indiana owns and operates Gibson Station Units 1–4 and owns 50.05% of Unit 5, but is the operator

(B) Includes Cayuga Internal Combustion (IC)

(C) Includes Wabash River IC

(D) Included in Assets Held for Sale

In addition, as of December 31, 2006, U.S. Franchised Electric and Gas owned approximately 20,700 conductor miles of electric transmission lines, including 600 miles of 525 kilovolts, 1,700 miles of 345 kilovolts, 3,300 miles of 230 kilovolts, 8,800 miles of 100 to 161 kilovolts, and 6,300 miles of 13 to 69 kilovolts. U.S. Franchised Electric and Gas also owned approximately 146,700 conductor miles of electric distribution lines, including 102,900 miles of overhead lines and 43,800 miles of underground lines, as of December 31, 2006 and approximately 8,900 miles of gas mains and service lines. As of December 31, 2006, the electric transmission and distribution systems had approximately 2,300 substations. U.S. Franchised Electric and Gas also owns three underground caverns with a total storage capacity of approximately 23 million gallons of liquid propane. This liquid propane is used in the three propane/air peak shaving plants located in Ohio and Kentucky. Propane/air peak shaving plants store propane and, when needed, vaporize the propane and mix with natural gas to supplement the natural gas supply during peak demand periods and emergencies.

Substantially all of Duke Energy Carolinas' electric plant in service is mortgaged under the indenture relating to Duke Energy's various series of First and Refunding Mortgage Bonds.

(For a map showing U.S. Franchised Electric and Gas' properties, see "Business—U.S. Franchised Electric and Gas" earlier in this section.)

NATURAL GAS TRANSMISSION

As discussed in Item 1. "Business", effective January 2, 2007, Duke Energy consummated the spin–off of its natural gas businesses, which includes the Natural Gas Transmission segment, to shareholders.

Texas Eastern's gas transmission system extends approximately 1,700 miles from producing fields in the Gulf Coast region of Texas and Louisiana to Ohio, Pennsylvania, New Jersey and New York. It consists of two parallel systems, one with three large–diameter parallel pipelines and the other with one to three large–diameter pipelines. Texas Eastern's onshore system consists of approximately 8,600 miles of pipeline and 73 compressor stations.

Texas Eastern also owns and operates two offshore Louisiana pipeline systems, which extend approximately 100 miles into the Gulf of Mexico and include approximately 500 miles of Texas Eastern's pipeline system and has an ownership interest in a processing plant in Southern Louisiana.

Texas Eastern has two joint–venture storage facilities in Pennsylvania and one wholly owned and operated storage field in Maryland. Texas Eastern's total working capacity in these three fields is 75 Bcf.

Algonquin connects with Texas Eastern's facilities in New Jersey, and extends approximately 250 miles through New Jersey, New York, Connecticut, Rhode Island and Massachusetts where it connects to Maritimes & Northeast Pipeline. The system consists of approximately 1,100 miles of pipeline with six compressor stations.

ETNG's transmission system crosses Texas Eastern's system at two points in Tennessee and consists of two mainline systems totaling approximately 1,400 miles of pipeline in Tennessee, Georgia, North Carolina and Virginia, with 18 compressor stations. ETNG has an LNG storage facility in Tennessee with a total working capacity of 1.2 Bcf. East Tennessee also connects to Saltville Gas Storage Company and Virginia Gas Storage Company. These natural gas storage fields are located in the state of Virginia and have a working gas capacity of approximately 5 Bcf.

Maritimes & Northeast Pipeline, LLC and Maritimes & Northeast Pipeline, LP (collectively, Maritimes & Northeast) transmission system (approximately 78% owned by Duke Energy) extends approximately 900 miles from producing fields in Nova Scotia through New Brunswick, Maine, New Hampshire and Massachusetts, connecting to Algonquin in Beverly, Massachusetts. It has two compressor stations on the system.

The British Columbia Pipeline System consists of two divisions. The field services division operates more than 1,840 miles of gathering pipelines in British Columbia, Alberta, the Yukon Territory and the Northwest Territories, as well as 22 field compressor stations; four gas processing plants located in British Columbia near Fort Nelson, Taylor, Chetwynd and in the Sikanni area Northwest of Fort St. John, and three elemental sulphur recovery plants located at Fort Nelson, Taylor and Chetwynd. Total contractible capacity is approximately 2.0 Bcf of residue gas per day. The pipeline division has approximately 1,740 miles of transmission pipelines in British Columbia and Alberta, as well as 18 mainline compressor stations

The Empress system is a collection of midstream assets involved in the extraction, storage, transportation, distribution and marketing of NGLs in Canada and the U.S. Assets include, among other things, an ownership interest in an NGL extraction plant on the TransCanada Alberta system, a liquids transmission pipeline, seven terminals along the pipe, two storage facilities, a fractionation facility, and an integrated NGL marketing and gas supply business. Total processing capacity of the Empress system is 2.4 Bcf of gas per day. The Empress system is located in Western Canada.

The DEGT Midstream operations are located in Western Canada and include thirteen natural gas processing plants and over 1,000 miles of natural gas gathering pipelines located in Western Canada.

Union Gas owns and operates natural gas transmission, distribution and storage facilities in Ontario. Union Gas' distribution system consists of approximately 22,000 miles of distribution pipelines. Union Gas' underground natural gas storage facilities have a working capacity of approximately 150 Bcf in 20 underground facilities located in depleted gas fields. Its transmission system consists of approximately 3,000 miles of pipeline and six mainline compressor stations.

MHP owns and operates two natural gas storage facilities, Moss Bluff and Egan, with a total storage capacity of approximately 31 Bcf. The Moss Bluff facility consists of three storage caverns located in Southeast Texas and has access to five pipeline systems. The Egan facility consists of three storage caverns located in South Central Louisiana and has access to eight pipeline systems.

Natural Gas Transmission also has a 50 percent investment in Gulfstream Natural Gas System, LLC (Gulfstream), a 691-mile interstate natural gas pipeline system owned and operated jointly by Duke Energy and The Williams Company, Inc.

(For a map showing natural gas transmission and storage properties, see "Business—Natural Gas Transmission" earlier in this section.)

FIELD SERVICES

(For information and a map showing Field Services' properties, see "Business—Field Services" earlier in this section.)

COMMERCIAL POWER

The following table provides information about Commercial Power's merchant generation portfolio as of December 31, 2006. The MW displayed in the table below are based on summer capacity.

Name	Gross MW	Net MW	Plant Type	Primary Fuel	Location	Approximate Ownership Interest (percentage)
Hanging Rock	1,240	1,240	Combined Cycle	Natural gas	OH	100
Lee	640	640	Simple Cycle	Natural gas	IL	100
Vermillion	640	480	Simple Cycle	Natural gas	IN	75
Fayette	620	620	Combined Cycle	Natural gas	PA	100
Washington	620	620	Combined Cycle	Natural gas	OH	100
Dick's Creek	152	152	Simple Cycle	Natural gas	OH	100
Beckjord CT	212	212	Simple Cycle	Fuel oil	OH	100
Miami Fort CT	60	60	Simple Cycle	Fuel oil	OH	100
Miami Fort (Units 7 and 8)(1)	1,080	720	Steam	Coal	OH	64
W.C. Beckjord(1)	1,124	862	Steam	Coal	OH	37.5
W.M. Zimmer(1)	1,300	605	Steam	Coal	OH	46.5
J.M. Stuart	2,340	912	Steam	Coal	OH	39
Killen(1)	600	198	Steam	Coal	OH	33
Conesville(1)	780	312	Steam	Coal	OH	40
Brownsville	466	466	Simple Cycle	Natural gas	TN	100
Total	11,874	8,099				

(1) Commercial Power generation facilities are jointly owned by Duke Energy Ohio and subsidiaries of American Electric Power, Inc. and Dayton Power and Light, Inc.

(For a map showing Commercial Power's properties, see "Business—Commercial Power" earlier in this section.)

INTERNATIONAL ENERGY

The following table provides information about International Energy's generation portfolio in continuing operations as of December 31, 2006

Name	Gross MW	Net MW	Fuel	Location	Approximate Ownership Interest (percentage)
Paranapanema	2,307	2,112	Hydro	Brazil	95%
Hidroelectrica Cerros Colorados	576	523	Hydro/Natural Gas	Argentina	91
Egenor	509	508	Hydro/Diesel	Peru	100
DEI Guatemala	250	250	Fuel Oil/Diesel	Guatemala	100
DEI El Salvador	291	263	Fuel Oil/Diesel	El Salvador	90
Electroquil	181	149	Diesel	Ecuador	82
Aguaytia	177	117	Natural Gas	Peru	66
Empresa Electrica Corani	147	74	Hydro	Bolivia	50
Total	4,438	3,996			

In December 2006, Duke Energy engaged in discussions with a potential buyer of International Energy's assets in Bolivia Such discussions to sell the assets were subject to a binding agreement between the parties, which was finalized in February 2007, and resulted in the sale of International Energy's 50 percent ownership interest in two hydroelectric power plants near Cochabamba, Bolivia to Econergy International.

International Energy also owns a 25% equity interest in NMC. In 2006, the NMC produced approximately 850 thousand metric tons of methanol and 1 million metric tons of MTBE. In addition, International Energy owns a 50% equity interest in the Campeche natural gas processing and compression facility Campeche has an installed processing capacity of 270 MMcf/d. International Energy also owns a 25% equity interest in Attiki, which is a natural gas distributor that has an exclusive 30 year license to supply natural gas to residential and commercial customers within the geographical area of Athens, Greece. (For additional information and a map showing International Energy's properties, see "Business—International Energy" earlier in this section.)

CRESCENT

(For information regarding Crescent's properties, see "Business—Crescent" earlier in this section.)

OTHER

(For information regarding the properties of the business unit now known as Other, see "Business—Other" earlier in this section.)

Item 3. Legal Proceedings.

For information regarding legal proceedings, including regulatory and environmental matters, see Note 4 to the Consolidated Financial Statements, "Regulatory Matters" and Note 17 to the Consolidated Financial Statements, "Commitments and Contingencies—Litigation" and "Commitments and Contingencies—Environmental."

Item 4. Submission of Matters to a Vote of Security Holders.

At the Duke Energy Corporation Annual Meeting of Shareholders on October 24, 2006, shareholders elected Roger Agnelli, Paul M. Anderson, William Barnet, III, G. Alex Bernhardt, Sr., Michael G. Browning, Phillip R. Cox, William T. Esrey, Ann Maynard Gray, James H. Hance, Jr., Dennis R. Hendrix, Michael E.J. Phelps, James T. Rhodes, James E. Rogers, Mary L. Schapiro and Dudley S. Taft to serve as directors until the next annual meeting of shareholders and until such Director's successor is duly elected and qualified. Below is a tabulation of votes with respect to each nominee for director at the meeting:

Nominee	For	Against/Withheld
Roger Agnelli	947,929,162	155,182,625
Paul M. Anderson	1,075,040,338	28,071,449
William Barnet, III	1,079,646,448	23,465,339
G. Alex Bernhardt, Sr.	1,075,727,658	27,384,129
Michael G. Browning	1,072,347,645	30,764,142
Phillip R. Cox	1,064,593,023	38,518,764
William T. Esrey	1,073,809,374	29,302,413
Ann Maynard Gray	1,068,607,394	34,504,393
James H. Hance, Jr.	1,072,614,825	30,496,962
Dennis R. Hendrix	1,072,182,705	30,929,082
Michael E. J. Phelps	752,240,344	350,871,443
James T. Rhodes	1,079,877,900	23,233,887
James E. Rogers	1,074,300,198	28,811,589
Mary L. Schapiro	1,076,085,064	27,026,723
Dudley S. Taft	1,062,145,116	40,966,671

In addition, shareholders at the meeting also approved the *Duke Energy Corporation 2006 Long-Term Incentive Compensation Plan*. There were 750,402,214 shares voted for the plan, 88,378,012 shares voted against the plan, and 15,211,175 shares abstained.

And, shareholders at the meeting also ratified the selection of Deloitte & Touche LLP to act as independent auditors for Duke Energy Corporation for 2006. There were 1,072,065,312 shares voted for the proposal, 20,828,427 shares voted against the proposal and 10,218,046 shares abstained.

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities.

Duke Energy's common stock is listed for trading on the New York Stock Exchange As of February 23, 2007, there were approximately 175,252 common stockholders of record.

Common Stock Data by Quarter

	2006			2005		
		Stock Price Range(a)			Stock Price Range(a)	
	Dividends Per Share	High	Low	Dividends Per Share	High	Low
First Quarter	$0.31	$ 29.77	$ 27.38	$0.275	$ 28.20	$ 24.37
Second Quarter(b)	0.63	29.85	26.94	0.585	29.98	27.34
Third Quarter	—	30.98	28.84	—	30.55	27.84
Fourth Quarter(b)	0.32	34.50	29.82	0.310	29.35	25.06

(a) Stock prices represent the intra-day high and low stock price.

(b) Dividends paid in September 2006 and December 2006 were increased from $0.31 per share to $0.32 per share.

On January 2, 2007, Duke Energy consummated the spin-off of the natural gas businesses to shareholders In connection with this transaction, Duke Energy distributed all the shares of common stock of Spectra Energy to Duke Energy shareholders. The distribution ratio approved by Duke Energy's Board of Directors was one-half share of Spectra Energy common stock for every share of Duke Energy common stock Subsequent to the distribution, the market price of Duke Energy common stock was significantly less than the 2006 trading ranges above due to the fact that a proportionate share of the value of Duke Energy stock prior to the spin-off was transferred to Spectra Energy. Additionally, future dividends paid on Duke Energy common stock are expected to be less than the 2006 dividend of $1 26 per share as dividends are anticipated to be split proportionately between Duke Energy and Spectra Energy such that the sum of the dividends of the two stand-alone companies approximates the former total dividend of Duke Energy. Duke Energy expects to continue its policy of paying regular cash dividends, although there is no assurance as to the amount of future dividends because they depend on future earnings, capital requirements, and financial condition. Future dividends are subject to declaration by the Board of Directors.

Issuer Purchases of Equity Securities for Fourth Quarter of 2006

None.

Duke Energy previously announced plans to execute up to approximately $2 5 billion in common stock repurchases over a three year period. On May 9, 2005, Duke Energy announced plans to suspend additional repurchases under the open-market purchase plan, pending further assessment, primarily due to the merger with Cinergy. At the time of suspension, Duke Energy had repurchased 32.6 million shares of common stock for approximately $0 9 billion. During the first quarter of 2006, Duke Energy announced the commencement of up to $1 billion of additional share repurchases under the previously announced plan. During the first six months of 2006, Duke Energy repurchased approximately 17 5 million shares of common stock for approximately $0.5 billion. In June 2006, in connection with the plan to spin off Duke Energy's natural gas businesses to Duke Energy shareholders, the share repurchase program was suspended. At the time of suspension, Duke Energy had repurchased approximately 50 million shares of common stock for approximately $1.4 billion under this repurchase plan. In October 2006, Duke Energy's Board of Directors authorized the reactivation of the share repurchase plan for Duke Energy of up to $500 million of share repurchases after the spin-off of the natural gas businesses has been completed. As of December 31, 2006, the dollar value of shares that may yet be purchased under the plan is approximately $1 1 billion.

Item 6. Selected Financial Data.[a]

	2006	2005	2004	2003(c)	2002
	(in millions, except per-share amounts)				
Statement of Operations					
Operating revenues	$15,184	$16,297	$19,596	$17,623	$14,757
Operating expenses	12,493	13,416	16,441	16,632	12,313
Gains on sales of investments in commercial and multi-family real estate	201	191	192	84	106
Gains (losses) on sales of other assets and other, net	276	534	(416)	(199)	32
Operating income	3,168	3,606	2,931	876	2,582
Other income and expenses, net	1,008	1,809	304	550	352
Interest expense	1,253	1,066	1,282	1,331	1,116
Minority interest expense	61	538	200	62	91
Earnings from continuing operations before income taxes	2,862	3,811	1,753	33	1,727
Income tax expense (benefit) from continuing operations	843	1,282	507	(52)	544
Income from continuing operations	2,019	2,529	1,246	85	1,183
(Loss) income from discontinued operations, net of tax	(156)	(701)	244	(1,246)	(149)
Income (loss) before cumulative effect of change in accounting principle	1,863	1,828	1,490	(1,161)	1,034
Cumulative effect of change in accounting principle, net of tax and minority interest	—	(4)	—	(162)	—
Net income (loss)	1,863	1,824	1,490	(1,323)	1,034
Dividends and premiums on redemption of preferred and preference stock	—	12	9	15	13
Earnings (loss) available for common stockholders	$ 1,863	$ 1,812	$ 1,481	$ (1,338)	$ 1,021

	2006	2005	2004	2003(c)	2002
Ratio of Earnings to Fixed Charges[d]	3.2	4.7	2.3	—(b)	2.0
Common Stock Data					
Shares of common stock outstanding[e]					
Year-end	1,257	928	957	911	895
Weighted average—basic	1,170	934	931	903	836
Weighted average—diluted	1,188	970	966	904	838
Earnings per share (from continuing operations)					
Basic	$ 1.73	$ 2.69	$ 1.33	$ 0.09	$ 1.41
Diluted	1.70	2.60	1.29	0.09	1.41
(Loss) earnings per share (from discontinued operations)					
Basic	$ (0.14)	$ (0.75)	$ 0.26	$ (1.39)	$ (0.19)
Diluted	(0.13)	(0.72)	0.25	(1.39)	(0.19)
Earnings (loss) per share (before cumulative effect of change in accounting principle)					
Basic	$ 1.59	$ 1.94	$ 1.59	$ (1.30)	$ 1.22
Diluted	1.57	1.88	1.54	(1.30)	1.22
Earnings (loss) per share					
Basic	$ 1.59	$ 1.94	$ 1.59	$ (1.48)	$ 1.22
Diluted	1.57	1.88	1.54	(1.48)	1.22
Dividends per share	1.26	1.17	1.10	1.10	1.10
Balance Sheet					
Total assets	$68,700	$54,723	$55,770	$57,485	$60,122
Long-term debt including capital leases, less current maturities	$18,118	$14,547	$16,932	$20,622	$20,221

(a) Significant transactions reflected in the results above include: 2006 merger with Cinergy (see Note 2 to the Consolidated Financial Statements, "Acquisitions and Dispositions"), 2006 Crescent joint venture transaction and subsequent deconsolidation effective September 7, 2006 (see Note 2 to the Consolidated Financial Statements, "Acquisitions and Dispositions), 2005 DENA disposition (see Note 13 to the Consolidated Financial Statements, "Discontinued Operations and Assets Held for Sale"), 2005 deconsolidation of DEFS effective July 1, 2005 (see Note 2 to the Consolidated Financial Statements, "Acquisitions and Dispositions"), 2005 DEFS sale of TEPPCO (see Note 2 to the Consolidated Financial Statements, "Acquisitions and Dispositions") and 2004 DENA sale of the Southeast plants (see Note 2 to the Consolidated Financial Statements, "Acquisitions and Dispositions")

(b) Earnings were inadequate to cover fixed charges by $241 million for the year ended December 31, 2003.

(c) As of January 1, 2003, Duke Energy adopted the remaining provisions of Emerging Issues Task Force (EITF) 02-03, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and for Contracts Involved in Energy Trading and Risk Management Activities" (EITF 02-03) and SFAS No. 143, "Accounting for Asset Retirement Obligations" (SFAS No. 143). In accordance with the transition guidance for these standards, Duke Energy recorded a net-of-tax and minority interest cumulative effect adjustment for change in accounting principles (See Note 1 to the Consolidated Financial Statements, "Summary of Significant Accounting Policies," for further discussion.)

(d) Includes pre-tax gains of approximately $0.9 billion, net of minority interest, related to the sale of TEPPCO GP and LP in 2005 (see Note 2 to the Consolidated Financial Statements, "Acquisitions and Dispositions").

(e) 2006 increase primarily attributable to issuance of approximately 313 million shares in connection with Duke Energy's merger with Cinergy (see Note 2 to the Consolidated Financial Statements, "Acquisitions and Dispositions")

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

INTRODUCTION

Management's Discussion and Analysis should be read in conjunction with the Consolidated Financial Statements and Notes for the years ended December 31, 2006, 2005 and 2004.

EXECUTIVE OVERVIEW

2006 Objectives. Duke Energy's objectives for 2006, as outlined in the 2006 Charter, consisted of the following:

- ~~Establish an industry-leading electric power platform through successful execution of the merger with Cinergy;~~
- Deliver on the 2006 financial objectives and position Duke Energy for growth in 2007 and beyond;
- Complete the exit of the former DENA business and pursue strategic portfolio opportunities;
- Build a high-performance culture focused on safety, diversity and inclusion, employee development, leadership and results; and
- Build credibility through leadership on key policy issues, transparent communications and excellent customer service.

During 2006, management executed on its objectives primarily through strategically completed and pending acquisitions, as well as dispositions of certain businesses with higher risk profiles, such as the former DENA operations outside the Midwest and the Cinergy commercial marketing and trading businesses. During 2006, Duke Energy created a business model that would give both Duke Energy's electric and gas businesses stand-alone strength and additional scope and scale along with steady and stable earnings growth.

On April 3, 2006, Duke Energy and Cinergy consummated the previously announced merger, which combined the Duke Energy and Cinergy regulated franchises as well as deregulated generation in the Midwestern United States. The merger with Cinergy increased the size and scope of Duke Energy's electric utility operations. Duke Energy management expects to achieve numerous synergies, both immediately and over time, in all regions impacted by the merger.

As a result of the additional size and scope of the electric utility operations discussed above, in June 2006, the Board of Directors of Duke Energy authorized management to pursue a plan to create two separate publicly traded companies by spinning off Duke Energy's natural gas businesses to Duke Energy shareholders, which was completed on January 2, 2007. The new natural gas company, Spectra Energy, consists of Duke Energy's Natural Gas Transmission business segment, including Union Gas, as well as Duke Energy's 50-percent ownership interest in DEFS. The spin off of the natural gas business is expected to deliver long-term value to shareholders as the two stand-alone companies are expected to be able to more easily participate in growth opportunities in their own industries as well as the gas and power industry consolidations.

In connection with the effort to reduce the risk profile of Duke Energy and to focus on businesses that can be expected to contribute steady, stable earnings growth, during 2006 Duke Energy finalized the sale of the former DENA power generation fleet outside of the Midwest to LS Power and the sale of the Cinergy commercial marketing and trading business to Fortis, a Benelux-based financial services group (Fortis).

Additionally, the Board of Directors of Duke Energy authorized management to explore the potential value of bringing in a joint venture partner at Crescent to expand the business and create a platform for increased growth. On September 7, 2006, an indirect wholly owned subsidiary of Duke Energy closed an agreement to create the Crescent JV with MS Members. As a result of the Crescent transaction, Duke Energy no longer controls the Crescent JV and on September 7, 2006 deconsolidated its investment in Crescent and subsequently accounts for its investment in the Crescent JV utilizing the equity method of accounting.

After completion of the spin-off of the natural gas businesses, the primary businesses remaining in Duke Energy in 2007 are the U.S. Franchised Electric and Gas business segment, the Commercial Power business segment, the International Energy business segment and Duke Energy's effective 50% interest in the Crescent JV, which management currently expects to continue to be a reportable business segment.

Duke Energy announced an agreement with Southern Company to evaluate the potential construction of a new nuclear power plant at a site jointly owned in Cherokee County, South Carolina. Additionally, Duke Energy continues to evaluate other opportunities to re-invest in the electric utility operations, by modernizing older coal-fired plants in the Carolinas and exploring the replacement of an aging coal plant in Indiana with a coal gasification plant. Also, during the fourth quarter of 2006, Duke Energy closed on a transaction to acquire from Dynegy a 825 megawatt power plant located in Rockingham County, North Carolina. This peaking plant, which will primarily be used during times of high electricity demand, generally in the winter and summer months, will provide customers with competitively priced peaking capacity and helps to ensure Duke Energy can meet growing customer demands for electricity in the foreseeable future. Additionally, in

December 2006 Duke Energy entered into an agreement to increase its ownership interest in the Catawba Nuclear Station for a purchase price of approximately $158 million. The purchase is subject to regulatory approvals and other conditions precedent and is expected to close prior to September 30, 2008.

Effective with the third quarter 2006, the Board of Directors of Duke Energy approved a quarterly dividend increase of $0.01 per share, increasing the annual dividend to $1.28 per share. Additionally, during 2006 Duke Energy repurchased approximately 17.5 million shares of its common stock for approximately $500 million. In connection with the above mentioned plan to spin off Duke Energy's natural gas businesses to Duke Energy shareholders, the share repurchase program was suspended. In October 2006, Duke Energy's Board of Directors authorized the reactivation of the share repurchase plan for Duke Energy of up to $500 million of share repurchases subsequent to the spin-off of the natural gas businesses on January 2, 2007.

2006 Financial Results. For the year-ended December 31, 2006, Duke Energy reported earnings available for common stockholders of $1,863 million and basic and diluted earnings per share (EPS) of $1.59 and $1.57, respectively, as compared to reported earnings available for common stockholders of $1,812 million and basic and diluted EPS of $1.94 and $1.88, respectively, for the year-ended December 31, 2005. Earnings available for common stockholders for 2006 as compared to 2005 were fairly flat; however, basic and diluted EPS were negatively impacted by the issuance of approximately 313 million shares in April 2006 in connection with the Cinergy merger. The highlights for 2006 include the following:

- U.S. Franchised Electric and Gas experienced higher earnings in 2006 primarily as a result of the addition of the former Cinergy regulated utility operations in the Midwest. These higher results were partially offset by milder weather, the impact of rate reductions related to Cinergy merger approvals, and lower bulk power marketing results in the Carolinas.

- Natural Gas Transmission's results were flat from 2005 to 2006, but were affected by strong commodity prices related to processing activities and higher operating and maintenance expenses.

- Field Services experienced lower earnings in 2006 primarily as a result of the 2005 gains on the sale of the TEPPCO investments and the transfer of a 19.7 percent interest in DEFS to ConocoPhillips in July 2005, which resulted in the deconsolidation of the investment in DEFS. Results in 2006 were favorably affected by strong commodity prices.

- Commercial Power experienced higher earnings in 2006 primarily as a result of the addition of the former Cinergy non-regulated generation operations in the Midwest, partially offset by the impacts of unfavorable purchase accounting charges as a result of recognizing the Cinergy assets and liabilities at their estimated fair values as of the date of merger.

- International Energy experienced lower earnings in 2006 primarily as a result of 2006 non-cash charges related to a settlement related to the Citrus litigation, an impairment charge related to the investment in Campeche, and an impairment charge related to the sale of Bolivian assets.

- Crescent experienced higher earnings in 2006 primarily as a result of the gain recognized on the joint venture transaction in September 2006, which resulted in the deconsolidation of Duke Energy's investment in the Crescent JV.

- Other experienced higher losses in 2006 primarily as a result of 2006 charges related to contract settlement negotiations, and costs to achieve the Cinergy merger and the spin-off of the natural gas businesses.

- Income tax expense from continuing operations was lower in 2006 as a result of a decrease in earnings from continuing operations before income taxes and a reduction in the effective tax rate. The reduction in the effective tax rate was primarily a result of favorable tax settlements on research and development costs and nuclear decommissioning costs, tax benefits related to the impairment of the investment in Bolivia, and tax credits recognized on synthetic fuel operations.

- During 2006, Duke Energy recognized net of tax losses of $156 million in discontinued operations, as compared to net of tax losses of $701 million in 2005. During 2006, Duke Energy completed the exit of the former DENA operations outside the Midwest region and recognized additional losses as a result of sales of certain contracts. Additionally, during 2006 Duke Energy exited the Cinergy commercial marketing and trading business.

2007 Objectives. As a result of the initiatives accomplished during 2006 and the spin-off of the natural gas businesses on January 2, 2007, Duke Energy is positioned as a lower-risk business with steady earnings growth potential. For 2007, management of Duke Energy is focused on the following objectives, as outlined in the 2007 Charter:

- Establish the identity and culture of the new Duke Energy, unifying its people, values, strategy, processes and systems;

- Optimize its operations by focusing on safety, simplicity, accountability, inclusion, customer satisfaction, cost management and employee development;

- Achieve public policy, regulatory and legislative outcomes that balance customers' needs for reliable energy at competitive prices with shareholders' expectation of superior returns;

- Invest in energy infrastructure that meets rising customer demands for reliable energy in an energy efficient and environmentally sound manner; and

- Achieve 2007 financial objectives and position Duke Energy to meet future growth targets.

Duke Energy's consolidated earnings during 2007 are anticipated to be reduced principally as a result of the spin-off of the natural gas businesses on January 2, 2007. Excluding the impacts of the spin-off of the natural gas businesses, earnings are anticipated to be favorably affected by the following factors: a full year of earnings from the Midwest operations acquired from Cinergy, realization of cost savings as the regulatory rate reductions shared with ratepayers will phase-out in 2007, customer sales growth, capital reinvestments and regulatory initiatives.

The majority of expected earnings in 2007 are anticipated to be contributed from U.S. Franchised Electric and Gas, which consists of Duke Energy's regulated businesses operating a net capacity of approximately 28,000 megawatts of generation. The regulated generation portfolio consists of a mix of coal, nuclear, natural gas and hydroelectric generation, with substantially all of the sales of electricity coming from coal and nuclear generation facilities. Commercial Power has net capacity of approximately 8,100 megawatts of unregulated generation, of which approximately 4,100 megawatts serves retail customers under the Rate Stabilization Plan in Ohio. Approximately 75% of International Energy's net capacity of approximately 4,000 megawatts of installed generation capacity in Latin America consists of baseload hydroelectric capacity that carries a low level of dispatch risk; in addition, for 2007 over 90% of International Energy's contractible capacity in Latin America is either currently contracted or receives a system capacity payment.

Duke Energy's total dividends and dividends per share in 2007 will be lower than in 2006 as a result of the spin-off of the natural gas businesses on January 2, 2007. Future dividends are expected to grow in connection with any earnings growth.

During the three-year period from 2007 to 2009, Duke Energy anticipates annual capital expenditures of approximately $3.5 billion, for a total of approximately $10 billion. These expenditures are principally related to expansion plans, environmental spending related to Clean Air requirements, nuclear fuel, as well as maintenance costs. Current estimates are that Duke Energy's regulated generation capacity will need to increase by approximately 6,400 megawatts over the next ten years, with the majority being in North and South Carolina and the remainder being in Indiana. Duke Energy is committed to adding base load capacity at a reasonable price while modernizing the current generation facilities by replacing older, less efficient plants with cleaner, more efficient plants. Significant expansion projects may include a new IGCC plant in Indiana, a new coal unit (or units) at Duke Energy's existing Cliffside facility in North Carolina, new gas-fired generation units and costs related to the evaluation of the potential construction of a new nuclear power plant in Cherokee County, South Carolina as well as normal additions due to system growth. Costs related to environmental spending are expected to decrease over the three-year period as the upgrades to comply with the new environmental regulations are completed. Duke Energy does not anticipate any additional capital investment related to its investment in the Crescent JV. Duke Energy does not currently anticipate funding 2007 capital expenditures with the issuance of common equity, but rather through the use of available cash and cash equivalents as well as the issuance of incremental debt.

As the majority of Duke Energy's anticipated future capital expenditures are related to its regulated operations, a significant risk to Duke Energy is the ability to recover in a timely manner costs related to such expansion. In Indiana, Duke Energy has been given approval to recover its development costs for the new IGCC plant. In North and South Carolina, Duke Energy will pursue legislation to provide for construction work in progress recovery for the additional unit (or units) at the Cliffside facility as well as the proposed nuclear power plant. Additionally, Duke Energy is attempting to obtain assurance of recovery of development costs related to the proposed nuclear power plant. Duke Energy does not anticipate beginning construction of the proposed nuclear power plant without adequate assurance of cost recovery from the state legislators or regulators. In November 2006, Duke Energy received approval for nearly $260 million of future federal tax credits related to costs to be incurred for the modernization of the Cliffside facility as well as the IGCC plant in Indiana.

In an effort to respond to concerns over climate change, the U.S. Congress recently discussed various proposals to reduce or cap carbon dioxide and other greenhouse gas emissions. Any legislation enacted as a result of these efforts could involve a market based cap and trade program. Duke Energy is also focusing on energy efficiency initiatives in an effort to reduce emissions.

Duke Energy's current regulatory initiatives primarily include obtaining the timely recovery of invested capital and pursuing a regulatory extension of the Rate Stabilization Plan in Ohio through 2010 as well as being a proponent of cost-effective energy efficiency initiatives. In North Carolina, Duke Energy is required by June 1, 2007 to file a rate case or show that a price adjustment is not required. During 2006, Duke Energy filed for an increase in its base electric rates in Kentucky. In December 2006, the Kentucky Public Service Commission approved an annual rate increase of $49 million to be effective January 1, 2007.

New energy legislation has been introduced in the current South Carolina legislative session which includes expansion of the annual fuel clause mechanism to include recovery of costs of reagents (ammonia, limestone, etc) that are consumed in the operation of Duke Energy Carolina's SO_2 and NOx control technologies The legislation also includes provisions to provide cost recovery assurance for upfront development costs associated with nuclear baseload generation, cost recovery assurance for construction costs associated with nuclear or coal baseload generation, and the ability to recover financing costs for new nuclear or coal baseload generation through annual riders Similar legislation is being discussed in North Carolina and may be introduced in the 2007 legislative session.

In summary, Duke Energy is coordinating its future capital expenditure requirements with regulatory initiatives in order to ensure adequate and timely cost recovery while continuing to provide low cost energy to its customers.

Economic Factors for Duke Energy's Business. Duke Energy's business model provides diversification between stable, less cyclical businesses like U.S. Franchised Electric and Gas, and the traditionally higher-growth and more cyclical energy businesses like Commercial Power and International Energy. Additionally, Crescent's portfolio strategy is diversified between residential, commercial and multi-family development. All of Duke Energy's businesses can be negatively affected by sustained downturns or sluggishness in the economy, including low market prices of commodities, all of which are beyond Duke Energy's control, and could impair Duke Energy's ability to meet its goals for 2007 and beyond.

Declines in demand for electricity as a result of economic downturns would reduce overall electricity sales and lessen Duke Energy's cash flows, especially as industrial customers reduce production and, thus, consumption of electricity A portion of U.S. Franchised Electric and Gas' business risk is mitigated by its regulated allowable rates of return and recovery of fuel costs under fuel adjustment clauses.

If negative market conditions should persist over time and estimated cash flows over the lives of Duke Energy's individual assets do not exceed the carrying value of those individual assets, asset impairments may occur in the future under existing accounting rules and diminish results of operations. A change in management's intent about the use of individual assets (held for use versus held for sale) or a change in fair value of assets held for sale could also result in impairments or losses.

Duke Energy's 2007 goals can also be substantially at risk due to the regulation of its businesses. Duke Energy's businesses in the United States are subject to regulations on the federal and state level. Regulations, applicable to the electric power industry, have a significant impact on the nature of the businesses and the manner in which they operate. Changes to regulations are ongoing and Duke Energy cannot predict the future course of changes in the regulatory environment or the ultimate effect that any future changes will have on its business

Duke Energy's earnings are impacted by fluctuations in commodity prices. Exposure to commodity prices generates higher earnings volatility in the unregulated businesses as there are timing differences as to when such costs are recovered in rates. To mitigate these risks, Duke Energy enters into derivative instruments to effectively hedge known exposures. With the 2006 sales of former DENA's assets outside the Midwestern United States, including substantially all the derivative portfolio, and Cinergy's marketing and trading operation, Duke Energy expects a less volatile earnings pattern going forward.

Additionally, Duke Energy's investments and projects located outside of the United States expose Duke Energy to risks related to laws of other countries, taxes, economic conditions, fluctuations in currency rates, political conditions and policies of foreign governments. Changes in these factors are difficult to predict and may impact Duke Energy's future results.

Duke Energy also relies on access to both short-term money markets and longer-term capital markets as a source of liquidity for capital requirements not met by cash flow from operations. An inability to access capital at competitive rates could adversely affect Duke Energy's ability to implement its strategy Market disruptions or a downgrade of Duke Energy's credit rating may increase its cost of borrowing or adversely affect its ability to access one or more sources of liquidity.

For further information related to management's assessment of Duke Energy's risk factors, see Item 1A. "Risk Factors."

RESULTS OF OPERATIONS

Consolidated Operating Revenues

Year Ended December 31, 2006 as Compared to December 31, 2005 Consolidated operating revenues for 2006 decreased $1,113 million, compared to 2005. This change was driven by:

- A $5,530 million decrease due to the deconsolidation of DEFS, effective July 1, 2005, and
- A $274 million decrease at Crescent due primarily to the deconsolidation of Crescent, effective September 7, 2006 and softening in the residential real estate market.

Partially offsetting these decreases in revenues were:

- An approximate $3,891 million increase due to the merger with Cinergy
- A $468 million increase at Natural Gas Transmission due primarily to Canadian assets (approximately $281 million), primarily higher processing revenues on the Empress System, favorable Canadian dollar foreign exchange impacts (approximately $157 million), and recovery of higher natural gas commodity costs (approximately $146 million), resulting from higher natural gas prices passed through to customers without a mark-up at Union Gas, partially offset by lower gas usage due to unseasonably warmer weather (approximately $186 million)
- A $216 million increase at International Energy due primarily to higher revenues in Peru from increased ownership and resulting consolidation of Aguaytia (approximately $118 million), higher energy prices in El Salvador (approximately $40 million), favorable results in Brazil, primarily foreign exchange rate impacts (approximately $31 million) and higher electricity volumes and prices in Argentina (approximately $27 million), and
- An approximate $130 million increase in Other related to the prior year impact of mark-to-market losses, primarily unrealized, due to increased commodity prices as a result of the discontinuance of certain cash flow hedges entered into to hedge Field Services' commodity price risk (see Note 8 to the Consolidated Financial Statements, "Risk Management and Hedging Activities, Credit Risk, and Financial Instruments") from February 22, 2005 to June 30, 2005. Effective with the deconsolidation of DEFS on July 1, 2005, mark-to-market changes related to these discontinued hedges are classified in *Other income and expenses, net* on the Consolidated Statements of Operations.

Year Ended December 31, 2005 as Compared to December 31, 2004. Consolidated operating revenues for 2005 decreased $3,299 million, compared to 2004. This change was driven by:

- A $5,380 million decrease due to the deconsolidation of DEFS, effective July 1, 2005, and
- An approximate $130 million decrease resulting from mark-to-market losses, primarily unrealized, due to increased commodity prices as a result of the discontinuance of certain cash flow hedges entered into to hedge Field Services' commodity price risk discussed above.

Partially offsetting these decreases in revenues were:

- An approximate $850 million increase at Field Services, excluding the impact of the deconsolidation of DEFS, due primarily to higher average commodity prices, primarily NGL and natural gas in the first six months of 2005
- A $704 million increase at Natural Gas Transmission due primarily to new Canadian assets (approximately $269 million), primarily the Empress System, favorable foreign exchange rates (approximately $153 million) as a result of the strengthening Canadian dollar (partially offset by currency impacts to expenses), higher natural gas prices that are passed through to customers (approximately $152 million), an increase related to U.S. business operations (approximately $60 million) driven by higher rates and contracted volumes and increased gas distribution revenues (approximately $36 million), resulting from higher gas usage in the power market
- A $363 million increase at U.S. Franchised Electric and Gas due primarily to increased sales to retail and wholesale customers as a result of warmer weather, more efficient performance of the generation fleet, and customer growth, coupled with an increase in fuel rates primarily as a result of higher coal costs in 2005 and increased market prices for wholesale power
- A $126 million increase at International Energy due primarily to favorable foreign exchange rate changes in Brazil, and higher energy prices and volumes, and
- A $58 million increase at Crescent due primarily to higher residential developed lot sales.

For a more detailed discussion of operating revenues, see the segment discussions that follow.

Consolidated Operating Expenses

Year Ended December 31, 2006 as Compared to December 31, 2005. Consolidated operating expenses for 2006 decreased $923 million, compared to 2005. The change was primarily driven by:

- An approximate $5,090 million decrease due to the deconsolidation of DEFS, effective July 1, 2005
- A $239 million decrease at Crescent due primarily to the deconsolidation of Crescent, effective September 7, 2006 and softening in the residential real estate market, and

- An approximate $120 million decrease associated with the prior year recognition of unrealized losses in accumulated other comprehensive income (AOCI) as a result of the discontinuance of certain cash flow hedges entered into to hedge Field Services' commodity price risk, which were previously accounted for as cash flow hedges (see Note 8 to the Consolidated Financial Statements, "Risk Management and Hedging Activities, Credit Risk, and Financial Instruments").

Partially offsetting these decreases in expenses were:

- An approximate $3,430 million increase due to the merger with Cinergy

- A $447 million increase at Natural Gas Transmission due primarily to Canadian assets (approximately $189 million), primarily the Empress System, increased natural gas prices at Union Gas (approximately $146 million), resulting from high natural gas prices passed through to customers without a mark-up at Union Gas, higher operating and maintenance, including pipeline integrity and project development expenses (approximately $133 million), Canadian dollar foreign exchange impacts (approximately $124 million), partially offset by lower gas purchase costs at Union Gas resulting primarily from unseasonably warmer weather (approximately $157 million)

- A $341 million increase at International Energy due primarily to higher costs in Peru (approximately $109 million), driven primarily by increased ownership and resulting consolidation of Aguaytia, a reserve related to a settlement made in conjunction with the Citrus litigation (approximately $100 million), higher fuel prices and increased consumption in El Salvador (approximately $38 million), unfavorable exchange rates, increased regulatory fees and higher purchased power costs in Brazil (approximately $34 million), an increase in Mexico due to an impairment of a note receivable from Campeche (approximately $33 million), and impairments in Bolivia (approximately $28 million)

- An $179 million increase in Other due primarily to costs to achieve the Cinergy merger and the anticipated spin-off of Duke Energy's natural gas businesses (approximately $128 million and $58 million, respectively), a reserve charge related to contract settlement negotiations (approximately $65 million), partially offset by decreases due to the continued wind-down of the former DENA businesses (approximately $47 million), and

- An approximate $115 million increase at Duke Energy Carolinas driven primarily by increased fuel expenses, due primarily to higher coal costs ($188 million) and increased purchase power expense resulting primarily from less generation availability during 2006 as a result of outages at base load stations ($42 million), partially offset by lower regulatory amortization, due primarily to reduced amortization of compliance costs related to clean air legislation ($86 million), and decreased operating and maintenance expense, due primarily to a December 2005 ice storm.

Year Ended December 31, 2005 as Compared to December 31, 2004. Consolidated operating expenses for 2005 decreased $3,025 million, compared to 2004. The change was primarily driven by:

- A $5,072 million decrease due to the deconsolidation of DEFS, effective July 1, 2005, and

- An approximate $100 million decrease in operating expenses at Commercial Power, mainly resulting from the sale of the Southeast Plants.

Partially offsetting these decreases in expenses were:

- An approximate $675 million increase in operating expenses at Field Services driven primarily by higher average NGL and natural gas prices in the first six months of 2005

- A $640 million increase at Natural Gas Transmission due primarily to new Canadian assets (approximately $272 million), primarily gas purchase costs associated with the Empress System, increased natural gas prices at Union Gas (approximately $152 million, which is offset in revenues), foreign exchange impacts (approximately $118 million) as discussed above (offset by currency impacts to revenues), and increased gas purchases for distribution (approximately $43 million) primarily due to higher gas usage in the power market

- A $346 million increase in operating expenses at U.S. Franchised Electric and Gas due primarily to increased fuel expenses, driven by higher coal costs and increased generation to meet customer demand, and increased operating and maintenance expenses due primarily to increased planned outage and maintenance at generating plants, planned maintenance to improve reliability of distribution and transmission equipment, and higher storm charges in 2005, driven primarily by an ice storm in December 2005

- An approximate $120 million increase related to the recognition of unrealized losses in AOCI as a result of the discontinuance of certain cash flow hedges entered into to hedge Field Services' commodity price risk, which were previously accounted for as cash flow hedges (see Note 8 to the Consolidated Financial Statements, "Risk Management and Hedging Activities, Credit Risk, and Financial Instruments")

- An approximate $75 million charge to increase liabilities associated with mutual insurance companies in 2005
- A $74 million increase at International Energy due primarily to higher fuel prices, increased fuel volumes purchased, higher maintenance costs and the impact of foreign exchange rate changes in Brazil, offset by decreased power purchase obligations in Brazil, and
- A $64 million increase as a result of the 2004 correction of an immaterial accounting error in prior periods related to reserves at Bison

For a more detailed discussion of operating expenses, see the segment discussions that follow.

Consolidated Gains on Sales of Investments in Commercial and Multi-Family Real Estate

Consolidated gains on sales of investments in commercial and multi-family real estate were $201 million in 2006, $191 million in 2005, and $192 million in 2004. The gain in 2006 was driven primarily by pre-tax gains from the sale of two office buildings at Potomac Yard in Washington, D.C. and a gain on a land sale at Lake Keowee in northwestern South Carolina. The gain in 2005 was driven primarily by pre-tax gains from the sales of surplus legacy land, particularly a large sale in Lancaster, South Carolina, commercial land sales, including a large sale near Washington, D.C. and multi-family project sales in North Carolina and Florida. The gain in 2004 was driven primarily by pre-tax gains from commercial land and project sales in the Washington D.C. area and pre-tax gains from the sales of surplus legacy land.

Consolidated Gains (Losses) on Sales of Other Assets and Other, net

Consolidated gains (losses) on sales of other assets and other, net was a gain of $276 million for 2006, a gain of $534 million for 2005, and a loss of $416 million for 2004. The gain in 2006 was due primarily to the pre-tax gains resulting from the sale of an effective 50% interest in Crescent, creating a joint venture between Duke Energy and MSREF (approximately $250 million), and gains on settlements of customers' transportation contracts at Natural Gas Transmission (approximately $28 million), partially offset by Commercial Power's losses on sales of emission allowances (approximately $29 million). The gain in 2005 was due primarily to the pre-tax gain resulting from the DEFS disposition transaction (approximately $575 million), partially offset by net pre-tax losses at Commercial Power, principally the termination of DENA structured power contracts in the Southeast region (approximately $75 million). The loss in 2004 was due primarily to pre-tax losses on the sale of the Southeast Plants (approximately $360 million) at Commercial Power, and the termination and sale of DETM contracts ($65 million) in Other.

Consolidated Operating Income

Year Ended December 31, 2006 as Compared to December 31, 2005. For 2006, consolidated operating income decreased $438 million, compared to 2005. Decreased operating income was primarily related to an approximate $575 million gain in 2005 resulting from the DEFS disposition transaction, the impacts of the deconsolidation of DEFS, effective July 1, 2005, which amounted to approximately $440 million for 2005, an approximate $190 million of cost in 2006 to achieve the Cinergy merger and the anticipated spin-off of Duke Energy's natural gas businesses, and approximately $165 million of charges in 2006 related to settlements and contract negotiations. Partially offsetting these decreases were an approximately $461 million of operating income generated by legacy Cinergy in 2006 as a result of the merger, an approximate $250 million gain in 2006 on the sale of an effective 50% interest in Crescent and an approximate $250 million negative impact to operating income in 2005 related to the discontinuance of certain cash flow hedges entered into to hedge Field Services' commodity price risk.

Year Ended December 31, 2005 as Compared to December 31, 2004. For 2005, consolidated operating income increased $675 million, compared to 2004. Increased operating income was due primarily to the gain in 2005 resulting from the DEFS disposition transaction and the charge in 2004 associated with the sale of the Southeast Plants in 2005, partially offset by charges in 2005 related to the discontinuance of certain cash flow hedges entered into to hedge Field Services' commodity price risk, charges in 2005 related to the termination of structured power contracts in the Southeast region and increased liabilities associated with mutual insurance companies.

Other drivers to operating income are discussed above. For more detailed discussions, see the segment discussions that follow.

Consolidated Other Income and Expenses

Year Ended December 31, 2006 as Compared to December 31, 2005. For 2006, consolidated other income and expenses decreased $801 million, compared to 2005. The decrease was due primarily to the $1,245 million pre-tax gains on sales of equity investments recorded in 2005, primarily associated with the sale of TEPPCO GP and Duke Energy's limited partner interest in TEPPCO LP, partially offset by an increase of approximately $253 million in equity in earnings of unconsolidated affiliates due primarily to the deconsolidation of DEFS starting July 1, 2005 and an increase of approximately $115 million of interest income resulting primarily from favorable income tax settlements in 2006.

Year Ended December 31, 2005 as Compared to December 31, 2004. For 2005, consolidated other income and expenses increased $1,505 million, compared to 2004 The increase was due primarily to the $1,245 million pre-tax gains associated with the sale of TEPPCO GP and Duke Energy's limited partner interest in TEPPCO LP, equity income of $292 million for the investment in DEFS subsequent to the deconsolidation of DEFS, effective July 1, 2005, slightly offset by the realized and unrealized pre-tax losses recognized in 2005 on certain derivative contracts hedging Field Services commodity price risk which were discontinued as cash flow hedges as a result of the deconsolidation of DEFS by Duke Energy Effective with the deconsolidation of DEFS on July 1, 2005, mark-to-market changes related to the Field Services discontinued hedges are classified in Other income and expenses, net on the Consolidated Statements of Operations, while from February 22, 2005 to June 30, 2005 these mark-to-market changes were classified in Non-regulated electric, natural gas, natural gas liquids and other revenues on the Consolidated Statements of Operations.

Consolidated Interest Expense

Year Ended December 31, 2006 as Compared to December 31, 2005. For 2006, consolidated interest expense increased $187 million, compared to 2005. This increase is primarily attributable to the increase in long-term debt as a result of the merger with Cinergy (an approximate $228 million impact), partially offset by reduced interest expense associated with DEFS, which was deconsolidated on July 1, 2005 (an approximate $82 million impact).

Year Ended December 31, 2005 as Compared to December 31, 2004. For 2005, consolidated interest expense decreased $216 million, compared to 2004. This decrease was due primarily to Duke Energy's debt reduction efforts in 2004 (an approximate $140 million impact) and the deconsolidation of DEFS effective July 1, 2005 (an approximate $80 million impact).

Consolidated Minority Interest Expense

Year Ended December 31, 2006 as Compared to December 31, 2005. For 2006, consolidated minority interest expense decreased $477 million, compared to 2005. This decrease primarily resulted from the 2005 gain associated with the sale of TEPPCO GP and the impact of deconsolidation of DEFS effective July 1, 2005.

Year Ended December 31, 2005 as Compared to December 31, 2004 For 2005, consolidated minority interest expense increased $338 million, compared to 2004. This increase was driven primarily by increased earnings at DEFS in the first six months of 2005 as a result of the sale of TEPPCO GP and higher commodity prices, offset by the impact of the deconsolidation of DEFS effective July 1, 2005.

Consolidated Income Tax Expense from Continuing Operations

Year Ended December 31, 2006 as Compared to December 31, 2005. For 2006, consolidated income tax expense from continuing operations decreased $439 million, compared to 2005. This decrease primarily resulted from lower pre-tax earnings, due primarily to the 2005 gains associated with the sale of TEPPCO GP and Duke Energy's limited partner interest in TEPPCO LP as discussed above, offset by the 2006 gain on Crescent. The effective tax rate decreased in 2006 (29%) compared to 2005 (34%). The lower effective tax rate for year ended December 31, 2006 as compared to December 31, 2005 was primarily due to favorable tax settlements on research and development costs and nuclear decommissioning costs, tax benefits related to the impairment of an investment in Bolivia, and reserves and tax credits recognized on synthetic fuel operations.

Year Ended December 31, 2005 as Compared to December 31, 2004. For 2005, consolidated income tax expense from continuing operations increased $775 million, compared to 2004. The increase in income tax expense from continuing operations is primarily a result of $2,058 million in higher pre-tax earnings, due primarily to the gains associated with the sale of TEPPCO GP, Duke Energy's limited partner interest in TEPPCO LP and the DEFS disposition transaction (see Note 2 to the Consolidated Financial Statements, "Acquisitions and Dispositions"). Other than the increase from higher pre-tax earnings, the increase in income tax expense from continuing operations is due to an increase in the effective tax rate, which was approximately 34% in 2005, as compared to approximately 29% in 2004. The increase in the effective tax rate was due primarily to the release of approximately $52 million of income tax reserves, resulting from the resolution of various outstanding income tax issues and changes in estimates in 2004 and a $20 million tax benefit in 2004 recognized in connection with the prior year formation of Duke Energy Americas, LLC, partially offset by the $45 million taxes recorded in 2004 on the repatriation of foreign earnings that was expected to occur in 2005 associated with the American Jobs Creation Act of 2004

Consolidated (Loss) Income from Discontinued Operations, net of tax

Consolidated (loss) income from discontinued operations was ($156) million for 2006, ($701) million for 2005, and $244 million for 2004. These amounts represent results of operations and gains (losses) on dispositions related primarily to former DENA's assets and contracts outside the Midwestern and Southeastern United States, which are included in Other, and Cinergy commercial marketing and trading operations, which are included in Commercial Power, (see Note 13 to the Consolidated Financial Statements, "Discontinued Operations and Assets Held for Sale"). The 2006 amount is primarily comprised of approximately $140 million of after-tax losses associated with certain contract terminations or sales at former DENA, as a result of the 2005 decision to exit substantially all of former DENA's remaining assets and contracts outside the Midwestern United States and certain contractual positions related to the Midwestern assets, and the recognition of approximately $17 million of after-tax losses associated with exiting the Cinergy commercial marketing and trading operations.

The 2005 amount is primarily comprised of an approximate $550 million non-cash, after-tax charge (approximately $900 million pre-tax) for the impairment of assets, and the discontinuance of hedge accounting and the discontinuance of the normal purchase/normal sale exception for certain positions, as a result of the decision to exit substantially all of former DENA's remaining assets and contracts outside the Midwestern United States and certain contractual positions related to the Midwestern assets. Additionally, during 2005, Duke Energy recognized after-tax losses of approximately $250 million (approximately $400 million pre-tax) as the result of selling certain gas transportation and structured contracts related to the former DENA operations. These charges were offset by the recognition of after-tax gains of approximately $125 million (approximately $200 million pre-tax) related to the recognition of deferred gains in AOCI related to discontinued cash flow hedges related to the former DENA operations.

The 2004 amount is primarily comprised of a $273 million after-tax gain resulting from the sale of International Energy's Asia-Pacific Business, and an approximate $117 million after-tax gain on the sale of two partially constructed merchant power plants in the western United States offset by operating losses at the western and northeast merchant power plants.

Consolidated Cumulative Effect of Change in Accounting Principle, net of tax and minority interest

During 2005, Duke Energy recorded a net-of-tax and minority interest cumulative effect adjustment for a change in accounting principle of $4 million as a reduction in earnings. The change in accounting principle related to the implementation of FIN 47, "Accounting for Conditional Asset Retirement Obligations," in which the timing or method of settlement are conditional on a future event that may or may not be within the control of Duke Energy.

Segment Results

Management evaluates segment performance based on earnings before interest and taxes from continuing operations, after deducting minority interest expense related to those profits (EBIT). On a segment basis, EBIT excludes discontinued operations, represents all profits from continuing operations (both operating and non-operating) before deducting interest and taxes, and is net of the minority interest expense related to those profits. Cash, cash equivalents and short-term investments are managed centrally by Duke Energy, so the gains and losses on foreign currency remeasurement, and interest and dividend income on those balances, are excluded from the segments' EBIT. Management considers segment EBIT to be a good indicator of each segment's operating performance from its continuing operations, as it represents the results of Duke Energy's ownership interest in operations without regard to financing methods or capital structures.

See Note 3 to the Consolidated Financial Statements, "Business Segments," for a discussion of Duke Energy's new segment structure

As discussed in Note 13 to the Consolidated Financial Statements, "Discontinued Operations and Assets Held for Sale" during the third quarter of 2005, the Board of Directors of Duke Energy authorized and directed management to execute the sale or disposition of substantially all former DENA's remaining assets and contracts outside the Midwestern United States and certain contractual positions related to the Midwestern assets. As a result of this exit plan, the continuing operations of the former DENA segment (which primarily include the operations of the Midwestern generation assets, former DENA's remaining Southeastern operations related to assets which were disposed of in 2004, the remaining operations of DETM, and certain general and administrative costs) have been reclassified to Commercial Power, except for DETM, which is in Other. Previously, the continuing operations of the former DENA segment were included as a component of Other in 2005 and as a component of the former DENA segment in prior periods.

Duke Energy's segment EBIT may not be comparable to a similarly titled measure of another company because other entities may not calculate EBIT in the same manner. Segment EBIT is summarized in the following table, and detailed discussions follow.

EBIT by Business Segment

	Years Ended December 31,				
	2006	2005	Variance 2006 vs 2005	2004	Variance 2005 vs 2004
	(in millions)				
U.S. Franchised Electric and Gas	$ 1,811	$ 1,495	$ 316	$ 1,467	$ 28
Natural Gas Transmission	1,438	1,388	50	1,329	59
Field Services[(a)]	569	1,946	(1,377)	367	1,579
Commercial Power[(b)]	21	(118)	139	(479)	361
International Energy	139	314	(175)	222	92
Crescent[(c)]	532	314	218	240	74
Total reportable segment EBIT	4,510	5,339	(829)	3,146	2,193
Other[(b)]	(581)	(518)	(63)	(207)	(311)
Total reportable segment and other EBIT	3,929	4,821	(892)	2,939	1,882
Interest expense	(1,253)	(1,066)	(187)	(1,282)	216
Interest income and other[(d)]	186	56	130	96	(40)
Consolidated earnings from continuing operations before income taxes	$ 2,862	$ 3,811	$ (949)	$ 1,753	$ 2,058

(a) In July 2005, Duke Energy completed the agreement with ConocoPhillips to reduce Duke Energy's ownership interest in DEFS from 69 7% to 50% Field Services segment data includes DEFS as a consolidated entity for periods prior to July 1, 2005 and an equity method investment for periods after June 30, 2005.

(b) Amounts associated with former DENA's operations are included in Other for all periods presented, except for the Midwestern generation and Southeast operations, which are reflected in Commercial Power.

(c) In September 2006, Duke Energy completed a joint venture transaction of Crescent. As a result, Crescent segment data includes Crescent as a consolidated entity for periods prior to September 7, 2006 and as an equity method investment for periods subsequent to September 7, 2006.

(d) Other includes foreign currency transaction gains and losses and additional minority interest expense not allocated to the segment results.

Minority interest expense as shown and discussed below includes only minority interest expense related to EBIT of Duke Energy's joint ventures. It does not include minority interest expense related to interest and taxes of the joint ventures.

The amounts discussed below include intercompany transactions that are eliminated in the Consolidated Financial Statements.

U.S. Franchised Electric and Gas

	Years Ended December 31,				
	2006	2005	Variance 2006 vs. 2005	2004	Variance 2005 vs. 2004
	(in millions, except where noted)				
Operating revenues	$ 8,098	$ 5,432	$ 2,666	$ 5,069	$ 363
Operating expenses	6,319	3,959	2,360	3,613	346
Gains (losses) on sales of other assets and other, net	—	7	(7)	3	4
Operating income	1,779	1,480	299	1,459	21
Other income and expenses, net	32	15	17	8	7
EBIT	$ 1,811	$ 1,495	$ 316	$ 1,467	$ 28

Duke Energy Carolinas GWh sales[a]	82,652	85,277	(2,625)	82,708	2,569
Duke Energy Midwest GWh sales[a][b]	46,069		46,069		

(a) Gigawatt-hours (GWh)

(b) Relates to operations of former Cinergy from the date of acquisition and thereafter

The following table shows the percentage changes in GWh sales and average number of customers for Duke Energy Carolinas. The table below excludes amounts related to legacy Cinergy since results of operations of Cinergy are only included from the date of acquisition and thereafter.

Increase (decrease) over prior year	2006	2005	2004
Residential sales	(1.2)%	3.7%	5.1%
General service sales	1.4%	1.9%	3.5%
Industrial sales	(3.8)%	1.1%	1.8%
Wholesale sales	(38.7)%	38.0%	(26.1)%
Total Duke Energy Carolinas sales[a]	(3.1)%	3.1%	(0.1)%
Average number of customers	2.0%	2.0%	1.7%

a Consists of all components of Duke Energy Carolinas' sales, including retail sales and wholesale sales to incorporated municipalities and to public and private utilities and power marketers.

Year Ended December 31, 2006 as Compared to December 31, 2005

Operating Revenues. The increase was driven primarily by:

- A $2,651 million increase in regulated revenues due to the acquisition of Cinergy
- A $203 million increase in fuel revenues driven by increased fuel rates for retail customers due primarily to increased coal costs. The delivered cost of coal in 2006 is approximately $11 per ton higher than the same period in 2005, representing an approximately 20% increase, and
- A $27 million increase related to demand from retail customers, due primarily to continued growth in the number of residential and general service customers in Duke Energy Carolinas' service territory. The number of customers in 2006 increased by approximately 45,000 compared to 2005.

Partially offsetting these increases were:

- A $91 million decrease in wholesale power sales, net of the impact of sharing of profits from wholesale power sales with industrial customers in North Carolina ($40 million). Sales volumes decreased by approximately 39% primarily due to production constraints caused by generation outages and pricing
- A $77 million decrease related to the sharing of anticipated merger savings by way of a rate decrement rider with regulated customers in North Carolina and South Carolina. As a requirement of the merger, Duke Energy Carolinas is required to share anticipated merger savings of approximately $118 million with North Carolina customers and approximately $40 million with South Carolina customers over a one year period, and
- A $32 million decrease in GWh sales to retail customers due to unfavorable weather conditions compared to the same period in 2005. Weather statistics in 2006 for heating degree days were approximately 9% below normal as compared to 2% above normal in 2005. Overall weather statistics for both heating and cooling periods in 2006 were unfavorable compared to the same periods in 2005.

Operating Expenses. The increase was driven primarily by:

- A $2,245 million increase in regulated operating expenses due to the acquisition of Cinergy
- A $188 million increase in fuel expenses, due primarily to higher coal costs. Fossil generation fueled by coal accounted for slightly more than 50% of total generation for year to date December 31, 2006 and 2005 and the delivered cost of coal in 2006 is approximately $11 per ton higher than the same period in 2005
- A $42 million increase in purchased power expense, due primarily to less generation availability during 2006 as a result of outages at base load stations, and
- A $24 million increase in depreciation expense, due to additional capital spending.

Partially offsetting these increases were:

- An $86 million decrease in regulatory amortization, due to reduced amortization of compliance costs related to clean air legislation during 2006 as compared to the same period in 2005. Regulatory amortization expenses were approximately $225 million for the year ended December 31, 2006 as compared to approximately $311 million during the same period in 2005
- A $39 million decrease in operating and maintenance expenses, due primarily to a December 2005 ice storm, and
- A $15 million decrease in donations related to sharing of profits from wholesale power sales with charitable, educational and economic development programs in North Carolina and South Carolina. For the year ended December 31, 2006, donations totaled $13 million, while for the same period in 2005, donations totaled $28 million

Other income and expenses. The increase in Other income and expenses resulted primarily from an increase in allowance for funds used during construction due mainly to the acquisition of the regulated operations of Cinergy.

EBIT. The increase in EBIT resulted primarily from the acquisition of the regulated operations of Cinergy, lower regulatory amortization in North Carolina, increased demand from retail customers due to continued growth in the number of residential and general service customers and decreased operating and maintenance expense in the Carolinas. These changes were partially offset by lower wholesale power sales, net of sharing, rate reductions due to the merger, unfavorable weather conditions and increased purchased power expense in the Carolinas.

Matters Impacting Future U.S. Franchised Electric and Gas Results

U.S. Franchised Electric and Gas continues to increase its customer base, maintain low costs and deliver high-quality customer service in the Carolinas and Midwest. The residential and general service sectors are expected to grow. U.S. Franchised Electric and Gas will continue to provide strong cash flows from operations to Duke Energy. Changes in weather, wholesale power market prices, service area economy, generation availability and changes to the regulatory environment would impact future financial results for U.S. Franchised Electric and Gas. Rate reductions for merger savings will primarily cease in the second quarter of 2007. In addition, U.S. Franchised Electric and Gas' results will be affected by its flexibility to vary the amortization expenses associated with the North Carolina clean air legislation. U.S. Franchised Electric and Gas amortization expense related to this clean air legislation totals $863 million from inception, with $311 million recorded in 2005 and $225 million recorded in 2006. At least $185 million of amortization will be recognized in 2007 in order to recognize the minimum cumulative amortization of approximately $1.05 billion required by the end of 2007.

Various regulatory activities will continue in 2007, including a North Carolina rate review and filings for certification for new generation and approval of various costs to be recovered in trackers. The outcomes of these matters will impact future earnings and cash flows for U.S. Franchised Electric and Gas. As a result of additional costs and synergies that are expected from the merger with Cinergy as well as the uncertainty related to the regulatory activities mentioned above, U.S. Franchised Electric and Gas is unable to estimate reported segment EBIT for 2007 and beyond. However, segment EBIT for 2007 is expected to be higher than in 2006 primarily due to a full-year of contributions from Cinergy's regulated operations and the expectation for more normalized weather in U.S. Franchised Electric and Gas' service territories.

Year Ended December 31, 2005 as Compared to December 31, 2004

Operating Revenues. The increase was driven primarily by:

- A $137 million increase in fuel revenues, due primarily to increased GWh sales to retail and wholesale customers and increased fuel rates for retail customers due primarily to increased coal costs. Sales to retail customers increased by approximately 2%, while sales to wholesale customers increased by approximately 40% resulting in significantly more fuel revenue collections from those customers. The delivered cost of coal in 2005 is approximately $7 per ton higher than in 2004
- A $109 million increase in wholesale power revenues, net of the impact of sharing of profits from wholesale power sales with industrial customers in North Carolina ($37 million), due primarily to increased sales volumes and higher market prices, approximately $42 million and $104 million, respectively. Wholesale GWh sales increased by approximately 40% due to strong demand driven by favorable weather, more efficient performance by the generation fleet in 2005 and alleviation of coal constraints that limited wholesale sales opportunities in 2004. Gross margin increased by $11,000 per GWh, an 80% increase, due to higher average market rates for power resulting primarily from energy supply disruptions and record natural gas prices in 2005
- A $55 million increase in GWh sales to retail customers due to favorable weather conditions during the latter half of the year. Weather statistics in 2005 for cooling degree days were approximately 7% better than normal as compared to 1% below normal in 2004, and
- A $27 million increase related to demand from retail customers, due primarily to continued growth in the number of residential and general service customers in Franchised Electric's service territory. The number of customers in 2005 increased by approximately 43,000 compared to 2004.

Operating Expenses. The increase was driven primarily by:

- A $176 million increase in fuel expenses, due primarily to higher coal costs and increased generation to meet the strong demand of retail and wholesale customers. Total generation increased by 4% compared to 2004 and generation fueled by coal accounted for more than 50 percent of total generation during both periods. The delivered cost of coal in 2005 is approximately $7 per ton higher than the same period in 2004

- A $134 million increase in operating and maintenance expenses, due primarily to increased planned outage and maintenance at generating plants, planned maintenance to improve the reliability of distribution and transmission equipment and employee wages and benefits

- A $29 million increase due to higher storm charges in 2005. The increase is primarily due to a December 2005 ice storm ($46 million), which resulted in outages for approximately 700,000 customers. This is partially offset by charges for Hurricane Ivan in September 2004 ($11 million) and a wind storm in March 2004 ($7 million), and

- A $14 million increase in donations related to sharing of profits from wholesale power sales with charitable, educational and economic development programs in North Carolina and South Carolina. For the year ended December 31, 2005, donations totaled $28 million, while for the same period in 2004, donations totaled $14 million.

EBIT. The increase in EBIT resulted primarily from increased sales to wholesale customers, net of sharing, increased sales to retail customers due to favorable weather in 2005, and continued growth in the number of residential and general service customers in 2005. These changes were partially offset by increased operating and maintenance expenses, including storm costs.

Natural Gas Transmission

	Years Ended December 31,				
	2006	2005	Variance 2006 vs 2005	2004	Variance 2005 vs 2004
	(in millions, except where noted)				
Operating revenues	$4,523	$4,055	$ 468	$3,351	$ 704
Operating expenses	3,162	2,715	447	2,075	640
Gains (losses) on sales of other assets and other, net	47	13	34	17	(4)
Operating income	1,408	1,353	55	1,293	60
Other income and expenses, net	69	65	4	63	2
Minority interest expense	39	30	9	27	3
EBIT	$1,438	$1,388	$ 50	$1,329	$ 59
Proportional throughput, TBtu[(a)]	3,248	3,410	(162)	3,332	78

(a) Trillion British thermal units. Revenues are not significantly impacted by pipeline throughput fluctuations since revenues are primarily composed of demand charges.

Year Ended December 31, 2006 as Compared to December 31, 2005

Operating Revenues. The increase was driven primarily by:

- A $281 million increase due to Canadian assets purchased in August 2005, primarily higher processing revenues on the Empress System as a result of commodity prices

- A $157 million increase due to foreign exchange rates favorably impacting revenues from the Canadian operations as a result of the strengthening Canadian dollar (partially offset by currency impacts to expenses),

- A $146 million increase from recovery of higher natural gas commodity costs, resulting from higher natural gas prices passed through to customers without a mark-up at Union Gas. This revenue increase is offset in expenses

- A $27 million increase in U.S. business operations driven by increased processing revenues associated with transportation, and

- A $26 million increase from completed and operational pipeline expansion projects in the U.S.

Partially offsetting these increases was:

- A $186 million decrease in gas distribution revenues at Union Gas primarily resulting from lower gas usage due to warmer weather compared to 2005

Operating Expenses. The increase was driven primarily by:

- A $189 million increase in gas purchase cost associated with the Empress System

- A $146 million increase related to increased natural gas prices at Union Gas. This amount is offset in revenues.

- A $133 million increase primarily related to increased operating and maintenance expenses on pipeline and storage operations, including pipeline integrity and project development expenses, higher insurance premiums, and benefit costs, and

- A $124 million increase caused by foreign exchange impacts (offset by currency impacts to revenues, as discussed above).

Partially offsetting these increases were:

- A $157 million decrease in gas purchase costs at Union Gas, primarily resulting from lower gas usage due to unseasonably warmer weather, and

- A $15 million decrease related to the resolution in 2006 of prior tax years' ad valorem tax issues

Gains (Losses) on Sales of Other Assets and Other, net. The increase was driven primarily by a $28 million gain in 2006 on the settlement of a customer's transportation contract, and a $5 million gain on the sale of Stone Mountain assets in 2006.

Other Income and Expenses, net. The increase was driven primarily a pre-tax SAB No. 51 gain of $15 million related to the Income Fund's issuance of additional units of the Canadian income trust fund, partially offset by a construction fee received in 2005 from an affiliate as a result of the successful completion of the Gulfstream Natural Gas System, LLC (Gulfstream), 50% owned by Duke Energy, and Natural Gas Transmission's 50% share of operating and maintenance expenses in 2006 on the Southeast Supply Header project.

EBIT. The increase in EBIT is due primarily to the increase in processing earnings (primarily Empress System), the gain on settlement of a customer's transportation contract, U.S. business expansion, the gain on the Income Fund's issuance of additional units of the Canadian income trust fund, a gain on a property insurance settlement and the strengthening Canadian currency, partially offset by increased operating and maintenance expenses, and lower Union results primarily due to weather.

Matters Impacting Future Natural Gas Transmission Results

In June 2006, the Board of Directors of Duke Energy authorized management to pursue a plan to create two separate publicly traded companies by spinning off Duke Energy's natural gas businesses to Duke Energy shareholders. This transaction was effective January 2, 2007. The new natural gas company, Spectra Energy, principally consists of Duke Energy's Natural Gas Transmission business segment and Duke Energy's 50-percent ownership interest in DEFS. The historical results of the natural gas businesses are expected to be treated as discontinued operations at Duke Energy in future periods beginning with the first quarter of 2007. As a result of the spin-off, Duke Energy's future results of operations will not include the operations of Spectra Energy.

Year Ended December 31, 2005 as Compared to December 31, 2004

Operating Revenues. The increase was driven primarily by:

- A $269 million increase due to new Canadian assets, primarily the Empress System

- A $153 million increase due to foreign exchange rates favorably impacting revenues from the Canadian operations as a result of the strengthening Canadian dollar (partially offset by currency impacts to expenses)

- A $152 million increase from recovery of higher natural gas commodity costs, resulting from higher natural gas prices that are passed through to customers without a mark-up at Union Gas. This revenues increase is offset in expenses

- A $60 million increase for U.S. business operations driven by higher rates at Maritimes & Northeast Pipeline, LLC and Maritimes & Northeast Pipeline, LP (collectively, M & N Pipeline) and favorable commodity prices on natural gas processing activities

- A $36 million increase in gas distribution revenues, primarily due to higher gas usage in the power market, and

- A $20 million increase from completed and operational pipeline expansion projects in the U.S.

Operating Expenses. The increase was driven primarily by:

- A $272 million increase due to new Canadian assets, primarily gas purchase costs associated with the Empress System

- A $152 million increase related to increased natural gas prices at Union Gas. This amount is offset in revenues

- A $118 million increase caused by foreign exchange impacts (offset by currency impacts to revenues, as discussed above)

- A $43 million increase in gas purchases for distribution, primarily due to higher gas usage in the power market, and

- A $23 million increase related to the 2004 resolution of ad valorem tax issues in various states.

Other Income and Expenses, net. The increase was driven primarily by the successful completion of the Gulfstream Phase II project which went into service in February 2005 and increased volumes at Gulfstream, resulting in a $11 million increase in Gas Transmission's 50% equity earnings and a $5 million construction fee received from an affiliate. These increases were partially offset by a $16 million gain in 2004 on the sale of equity investments, primarily due to the resolution of contingencies related to prior year sales.

EBIT. The increase in EBIT was due primarily to earnings from U.S. business expansion projects, improved U.S. operations and favorable foreign exchange rate impacts from the strengthening Canadian currency, partially offset by the 2004 resolution of ad valorem tax issues.

Field Services

	Years Ended December 31,				
	2006	2005	Variance 2006 vs 2005	2004	Variance 2005 vs 2004
	(in millions, except where noted)				
Operating revenues	$ —	$5,530	$ (5,530)	$10,044	$ (4,514)
Operating expenses	5	5,215	(5,210)	9,489	(4,274)
Gains (losses) on sales of other assets and other, net	—	577	(577)	2	575
Operating income	(5)	892	(897)	557	335
Equity in earnings of unconsolidated affiliates[a]	574	292	282	—	292
Other income and expenses, net	—	1,259	(1,259)	37	1,222
Minority interest expense	—	497	(497)	227	270
EBIT	$ 569	$1,946	$ (1,377)	$ 367	$ 1,579
Natural gas gathered and processed/transported, TBtu/d[b]	6.8	6.8	—	6.8	—
NGL production, MBbl/d[c]	361	353	8	356	(3)
Average natural gas price per MMBtu[d]	$7.23	$ 8.59	$ (1.36)	$ 6.14	$ 2.45
Average NGL price per gallon[e]	$0.94	$ 0.85	$ 0.09	$ 0.68	$ 0.17

(a) Includes Duke Energy's 50% equity in earnings of DEFS net income subsequent to the deconsolidation of DEFS effective July 1, 2005. Results of DEFS prior to July 1, 2005 are presented on a consolidated basis.

(b) Trillion British thermal units per day

(c) Thousand barrels per day

(d) Million British thermal units. Average price based on NYMEX Henry Hub

(e) Does not reflect results of commodity hedges

In July 2005, Duke Energy completed the transfer of a 19.7% interest in DEFS to ConocoPhillips, Duke Energy's co-equity owner in DEFS, which reduced Duke Energy's ownership interest in DEFS from 69.7% to 50% (the DEFS disposition transaction) and resulted in Duke Energy and ConocoPhillips becoming equal 50% owners in DEFS. As a result of the DEFS disposition transaction, Duke Energy deconsolidated its investment in DEFS and subsequently has accounted for DEFS as an investment utilizing the equity method of accounting (see Note 2 to the Consolidated Financial Statements, "Acquisitions and Dispositions").

Year Ended December 31, 2006 as Compared to December 31, 2005

Operating Revenues. The decrease was due to the DEFS disposition transaction and subsequent deconsolidation of DEFS.

Operating Expenses. The decrease was due to the DEFS disposition transaction and subsequent deconsolidation of DEFS. Operating expenses for 2005 were also impacted by approximately $120 million of losses recognized due to the reclassification of pre-tax unrealized losses in AOCI as a result of the discontinuance of certain cash flow hedges entered into to hedge Field Services' commodity price risk, which were previously accounted for as cash flow hedges.

Gains (losses) on sales of other assets and other, net. The decrease was due primarily to an approximate pre-tax gain of $575 million on the DEFS disposition transaction in the prior year.

Equity in Earnings of Unconsolidated Affiliates. The increase is due to Duke Energy's 50% of equity in earnings of DEFS' net income for the twelve months ended December 31, 2006 as compared to equity in earnings of DEFS' net income for the six months ended December 31, 2005. DEFS' earnings during the twelve months ended December 31, 2006 have continued to be favorably impacted by increased NGL and crude oil prices as compared to the prior period, as well as increased trading and marketing gains due primarily to changes in natural gas prices and the timing of derivative and inventory transactions.

Other Income and Expenses, net. The decrease is due to the DEFS disposition transaction and subsequent deconsolidation of DEFS. In 2005, DEFS had a pre-tax gain on the sale of its wholly-owned subsidiary, TEPPCO GP, the general partner of TEPPCO LP of $1.1 billion, and Duke Energy had a pre-tax gain on the sale of its limited partner interest in TEPPCO LP of approximately $97 million. TEPPCO GP and Duke Energy's limited partner interest in TEPPCO LP were each sold to Enterprise GP Holdings LP, an unrelated third party.

Minority Interest Expense. The decrease was due to the DEFS disposition transaction and subsequent deconsolidation of DEFS. Minority interest expense for 2005 was due primarily to the gain on the sale of TEPPCO GP to Enterprise GP Holdings LP for approximately $1.1 billion, as discussed above.

EBIT The decrease in EBIT from 2006 to 2005 resulted primarily from the gain on sale of TEPPCO GP and Duke Energy's limited partner interest in TEPPCO LP in 2005 and gain on the DEFS disposition transaction in 2005, which reduced Duke Energy's ownership interest in DEFS from 69.7% to 50%. These decreases were partially offset by increased NGL and crude oil prices in 2006 as compared to the prior year.

Matters Impacting Future Field Services Results

In June 2006, the Board of Directors of Duke Energy authorized management to pursue a plan to create two separate publicly traded companies by spinning off Duke Energy's natural gas businesses to Duke Energy shareholders. This transaction was effective January 2, 2007. The new natural gas company, Spectra Energy, principally consists of Duke Energy's Natural Gas Transmission business segment, including Union Gas, and Duke Energy's 50-percent ownership interest in DEFS. The historical results of the natural gas businesses are expected to be treated as discontinued operations at Duke Energy in future periods beginning with the first quarter of 2007. As a result of the spin-off, Duke Energy's future results of operations will not include the operations of Spectra Energy.

Year Ended December 31, 2005 as Compared to December 31, 2004

Operating Revenues. The decrease was due to the DEFS disposition transaction and subsequent deconsolidation of DEFS. This decrease was partially offset by increased revenues of approximately $850 million during the six months ended June 30, 2005 versus the comparable period in the prior year which was primarily attributable to a $0.14 per gallon increase in average NGL prices and a $0.66 per MMBtu increase in average natural gas prices. Subsequent to June 2005, Duke Energy's 50% of equity in earnings related to its investment in DEFS are included in Equity in Earnings of Unconsolidated Affiliates.

Operating Expenses. The decrease was due to the DEFS disposition transaction and subsequent deconsolidation of DEFS. Subsequent to June 2005, the results of DEFS are included in Equity in Earnings of Unconsolidated Affiliates. This decrease was partially offset by:

- Increased operating expense of approximately $675 million during the six months ended June 30, 2005 versus the comparable period in the prior year which was primarily attributable to higher average costs of raw natural gas supply, due primarily to an increase in average NGL and natural gas prices, and

- An approximate $120 million increase due to the reclassification of pre-tax unrealized losses in AOCI during the first quarter 2005 as a result of the discontinuance of certain cash flow hedges entered into to hedge Field Services' commodity price risk, which were previously accounted for as cash flow hedges (see Note 8 to the *Consolidated Financial Statements*, "Risk Management and Hedging Activities, Credit Risk, and Financial Instruments"). After the discontinuance of these hedges, changes in their fair value are being recognized in Other results, as management considers the discontinuance to be an event which disassociates the contracts from the Field Services' results.

Gains (losses) on sales of other assets and other, net. The increase was primarily due to an approximate pre-tax gain of $575 million on the DEFS disposition transaction.

Equity in earnings of unconsolidated affiliates. The increase was driven by the equity in earnings of $292 million for Duke Energy's investment in DEFS subsequent to the completion of the DEFS disposition transaction and related deconsolidation. DEFS earnings during the six months ended December 31, 2005 have continued to be favorably impacted by increased commodity prices. These increases were partially offset by higher operating costs and pipeline integrity work as well as lower volumes due in part to hurricane interruptions.

Other Income and Expenses, net. The increase was driven primarily by an approximate $1.1 billion pre-tax gain in 2005 on the sale of DEFS' wholly-owned subsidiary, TEPPCO GP, the general partner of TEPPCO LP, and the pre-tax gain on the sale of Duke Energy's limited partner interest in TEPPCO LP of approximately $100 million. TEPPCO GP and Duke Energy's limited partner interest in TEPPCO LP were each sold to Enterprise GP Holdings LP, an unrelated third party. The gain was partially offset by a $33 million decrease in earnings from equity method investments, primarily as a result of the sale of TEPPCO GP and Duke Energy's limited partner interest in TEPPCO LP in the first quarter of 2005.

Minority Interest Expense. The increase was due primarily to the minority interest impact of the gain on the sale of TEPPCO GP to Enterprise GP Holdings LP for approximately $1.1 billion as well as increased earnings at DEFS during the six months ended June 30, 2005 due to commodity price increases. This increase was partially offset by the DEFS disposition transaction and the related deconsolidation of Duke Energy's investment in DEFS effective July 1, 2005.

EBIT. The increase was primarily driven by the gain on sale of TEPPCO GP and Duke Energy's limited partner interest in TEPPCO LP, the gain as a result of the DEFS disposition transaction and favorable effects of commodity price increases, partially offset by the impact of Duke Energy's decreased ownership percentage resulting from the completion of the DEFS disposition transaction. Also, during the first three months of 2005, Duke Energy discontinued certain cash flow hedges entered into to hedge Field Services' commodity price risk (see Note 8 to the Consolidated Financial Statements, "Risk Management and Hedging Activities, Credit Risk, and Financial Instruments"). As a result of the discontinuance of these cash flow hedges and hedge accounting treatment, approximately $120 million of pre-tax unrealized losses in AOCI related to these contracts have been recognized by Field Services during the year ended December 31, 2005. Field Services' future results are subject to volatility for factors such as commodity price changes.

Supplemental Data

Below is supplemental information for DEFS operating results subsequent to deconsolidation on July 1, 2005:

(in millions)	Twelve Months Ended December 31, 2006	Six Months Ended December 31, 2005
Operating revenues	$ 12,335	$ 7,463
Operating expenses	11,063	6,814
Operating income	1,272	649
Other income and expenses, net	9	1
Interest expense, net	119	62
Income tax expense	23	4
Net income	$ 1,139	$ 584

Commercial Power

	Years Ended December 31,				
	2006	2005	Variance 2006 vs 2005	2004	Variance 2005 vs 2004
	(in millions, except where noted)				
Operating revenues	$ 1,402	$ 148	$ 1,254	$ 179	$ (31)
Operating expenses	1,395	200	1,195	302	(102)
Gains (losses) on sales of other assets and other, net	(23)	(70)	47	(359)	289
Operating income	(16)	(122)	106	(482)	360
Other income and expenses, net	37	4	33	3	1
EBIT	$ 21	$ (118)	$ 139	$ (479)	$ 361
Actual plant production, GWh[a]	17,640	1,759	15,881	3,343	(1,584)
Net proportional megawatt capacity in operation	8,100	3,600	4,500	3,600	—

(a) Excludes discontinued operations

During the third quarter of 2005, the Board of Directors of Duke Energy authorized and directed management to execute the sale or disposition of substantially all of former DENA's remaining assets and contracts outside the Midwestern United States and certain contractual positions related to the Midwestern assets. As a result of this exit plan, Commercial Power includes the operations of former DENA's Midwestern generation assets and remaining Southeastern operations related to the assets which were disposed of in 2004. The results of former DENA's discontinued operations, which are comprised of assets sold to LS Power, are presented in (Loss) Income From Discontinued Operations, net of tax, on the Consolidated Statements of Operations, and are discussed in consolidated Results of Operations section titled "Consolidated (Loss) Income from Discontinued Operations, net of tax."

Year Ended December 31, 2006 as compared to December 31, 2005

Operating Revenues. The increase was primarily driven by the acquisition of Cinergy non-regulated generation assets for which results, including the impacts of purchase accounting, are reflected from the date of acquisition and thereafter, but are not included in the same period in 2005 (approximately $1,240 million). Operating revenues associated with the former DENA Midwest plants were approximately $14 million higher in 2006 compared to 2005 due primarily to higher average prices and slightly higher volumes.

Operating Expenses. The increase was primarily driven by the acquisition of Cinergy non-regulated generation assets for which results, including the impacts of purchase accounting, are reflected from the date of acquisition and thereafter, but are not included in the same period in 2005 (approximately $1,185 million).

Gain (losses) on Sales of Other Assets and Other, net. The increase was driven primarily by an approximate $75 million pre-tax charge in 2005 related to the termination of structured power contracts in the Southeastern Region and an approximate $6 million gain on the sale of the Pine Mountain synthetic fuel facility in 2006, partially offset by net losses of approximately $29 million on sales of emission allowances in 2006.

Other Income and Expenses, net. The increase is driven primarily by equity earnings of unconsolidated affiliates related to investments acquired in connection with the Cinergy merger in 2006.

EBIT. The increase was due primarily by the approximate $75 million pre-tax charge in 2005 related to the termination of structured power contracts in the Southeastern Region and the acquisition of Cinergy assets (approximately $69 million).

Matters Impacting Future Commercial Power Results

Commercial Power's current strategy is focused on maximizing the returns and cash flows from its current portfolio. Results for Commercial Power are sensitive to changes in power supply, power demand and fuel prices.

Segment EBIT for 2007 is expected to be higher than in 2006 primarily due to the impacts of a full year of contributions from Cinergy's Midwestern non-regulated generation portfolio, impacts of purchase accounting from the Cinergy merger, and the recovery of under-collected fuel costs in 2006. Future results for Commercial Power are subject to volatility due to the over or under-collection of fuel costs since Commercial Power is not subject to regulatory accounting pursuant to SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation." In addition, the outcome of the remand hearing by the Ohio Supreme Court in regard to the Rate Stabilization Plan (RSP) with the PUCO could affect the current tariff structure of the RSP.

Year Ended December 31, 2005 as compared to December 31, 2004

Operating Revenues. The decrease was driven primarily by the sale of the Southeast plants in 2004, including losses in 2005 associated with structured power contracts in the Southeast.

Operating Expenses. The decrease was driven primarily by the sale of the Southeast plants in 2004 and lower operating expenses in the Midwest, including:

- $61 million decrease in operations and maintenance costs, including general and administrative expenses, and depreciation expenses, and
- $38 million decrease in fuel costs.

Gains (losses) on sales of other assets and other, net. The 2005 loss was due primarily to an approximate $75 million pre-tax charge related to the termination of structured power contracts in the Southeastern Region. The 2004 results include pre-tax losses of approximately $360 million associated with the sale of the Southeast Plants.

EBIT. EBIT loss decreased driven by the loss recognized in 2004 on the sale of the Southeast Plants and decreased operating costs and lower general and administrative expense, as outlined above.

International Energy

	Years Ended December 31,				
	2006	2005	Variance 2006 vs 2005	2004	Variance 2005 vs 2004
	(in millions, except where noted)				
Operating revenues	$ 961	$ 745	$ 216	$ 619	$ 126
Operating expenses	877	536	341	462	74
Gains (losses) on sales of other assets and other, net	(1)	—	(1)	(3)	3
Operating income	83	209	(126)	154	55
Other income and expenses, net	76	117	(41)	78	39
Minority interest expense	20	12	8	10	2
EBIT	$ 139	$ 314	$ (175)	$ 222	$ 92
Sales, GWh	20,424	18,213	2,211	17,776	437
Net proportional megawatt capacity in operation[(a)]	3,996	3,937	58	4,139	(202)

(a) Excludes discontinued operations

Year Ended December 31, 2006 as Compared to December 31, 2005

Operating Revenues. The increase was driven primarily by:

- A $118 million increase in Peru due to increased ownership and resulting consolidation of Aguaytia (See Note 2 in the Consolidated Financial Statements, "Acquisitions and Dispositions") and an increase in Egenor due to higher sales volumes, offset by lower prices
- A $40 million increase in El Salvador due to higher energy prices
- A $31 million increase in Brazil due to the strengthening of the Brazilian Real against the U.S. dollar and higher average energy prices, offset by lower volumes, and
- A $27 million increase in Argentina primarily due to higher electricity generation, prices and increased gas marketing sales.

Operating Expenses. The increase was driven primarily by:

- A $109 million increase in Peru due to increased ownership and resulting consolidation of Aguaytia (See Note 2 in the Consolidated Financial Statements, "Acquisitions and Dispositions") and increased purchased power and fuel costs in Egenor
- A $100 million increase due to a reserve established as a result of a settlement made in conjunction with the Citrus litigation (see Note 17 to the Consolidated Financial Statements, "Commitments and Contingencies")
- A $38 million increase in El Salvador primarily due to higher fuel prices and increased fuel consumption
- A $34 million increase in Brazil due to the strengthening of the Brazilian Real against the U.S. dollar, increased regulatory fees, and purchased power costs
- A $33 million increase in Mexico due to an impairment of a note receivable from Campeche, and
- A $28 million increase in Bolivia due primarily to impairment charges as a result of the sale of assets in Bolivia, which was completed in February 2007.

Other Income and expenses, net. The decrease was primarily driven by a $26 million decrease in NMC due to lower MTBE margins and unplanned outages and a $12 million decrease as a result of consolidation of Aguaytia in 2006 (See Note 2 in the Consolidated Financial Statements, "Acquisitions and Dispositions").

EBIT. The decrease in EBIT was primarily due to a litigation provision, impairments in Mexico and Bolivia, lower margins at NMC, higher purchased power costs in Egenor, offset by favorable hydrology and pricing in Argentina.

Matters Impacting Future International Energy Results

International Energy's current strategy is focused on selectively growing its Latin American power generation business while continuing to maximize the returns and cash flow from its current portfolio. Results for International Energy are sensitive to changes in hydrology, power supply, power demand and fuel prices. Regulatory matters can also impact International Energy results, as well as impacts from fluctuations in exchange rates, most notably the Brazilian Real.

Certain of International Energy's long-term sales contracts and long-term debt in Brazil contain inflation adjustment clauses. While this is favorable to revenue in periods of inflation in the long run, as International Energy's contract prices are adjusted, there is an unfavorable impact on interest expense resulting from revaluation of International Energy's outstanding local currency debt. In periods of deflation, revenue is negatively impacted and interest expense is positively impacted.

International Energy's Argentine operations are participating in a government sponsored project to construct and operate additional gas-fired generation capacity in Argentina. International Energy's future results of operations may be impacted by the Argentine government's ability to successfully carry out this project and provide an adequate return to entities participating in the project.

Year Ended December 31, 2005 as Compared to December 31, 2004

Operating Revenues. The increase was driven primarily by:

- A $32 million increase in Brazil due to favorable exchange rates, higher average energy prices, partially offset by lower sales volumes
- A $31 million increase in El Salvador due to higher power prices and a favorable change in regulatory price bid methodology
- A $28 million increase in Argentina due primarily to higher power prices and hydroelectric generation
- A $14 million increase in Ecuador mainly due to higher volumes resulting from a lack of water for hydro competitors

- A $12 million increase in Guatemala due to higher power prices, and
- An $8 million increase in Peru due to favorable hydrological conditions and higher power prices.

Operating Expenses. The increase was driven primarily by:

- A $29 million increase in El Salvador due primarily to higher fuel oil prices, increased fuel oil volumes purchased and increased transmission costs
- A $26 million increase in Ecuador due to higher maintenance, higher diesel fuel prices, increased diesel fuel volumes purchased and a prior year credit related to long term service contract termination
- A $15 million increase in Guatemala due to higher fuel prices and increased fuel volumes purchased, in addition to higher operations and maintenance costs
- A $14 million increase in Brazil due to unfavorable exchange rates and an increase in regulatory and transmission fees, partially offset by lower power purchase obligations, and
- A $14 million increase in Argentina due to higher power purchase volumes and prices.

Partially offsetting these increases were;

- A $13 million decrease related to a 2004 charge for the disposition of the ownership share in Compania de Nitrogeno de Cantarell, S.A. de C.V. (Cantarell), a nitrogen production and delivery facility in the Bay of Campeche, Gulf of Mexico in 2004, and
- A $10 million decrease in general and administrative expenses primarily due to lower corporate overhead allocations and compliance costs.

Other Income and Expenses, net. The increase was driven primarily by a $55 million increase in equity earnings from the NMC investment driven by higher product margins, offset by a $20 million equity investment impairment related to Campeche in 2005.

EBIT. The increase was due primarily to favorable pricing and hydrological conditions in Peru and Argentina, favorable exchange rates in Brazil and higher equity earnings from NMC, absence of a charge associated with the disposition of the ownership share in Cantarell recorded in 2004, partially offset by an equity investment impairment related to Campeche in 2005.

Crescent[(a)]

	Years Ended December 31,				
	2006	2005	Variance 2006 vs 2005	2004	Variance 2005 vs 2004
			(in millions)		
Operating revenues	$221	$495	$ (274)	$437	$ 58
Operating expenses	160	399	(239)	393	6
Gains on sales of investments in commercial and multi-family real estate	201	191	10	192	(1)
Gains (losses) on sales of other assets and other, net	246	—	246	—	—
Operating income	508	287	221	236	51
Equity in earnings of unconsolidated affiliates	15	—	15	—	—
Other income and expenses, net	14	44	(30)	3	41
Minority interest expense	5	17	(12)	(1)	18
EBIT	$532	$314	$ 218	$240	$ 74

(a) In September 2006, Duke Energy completed a joint venture transaction at Crescent. As a result, Crescent segment data includes Crescent as a consolidated entity for periods prior to September 7, 2006 and as an equity investment for the periods subsequent to September 7, 2006.

Year Ended December 31, 2006 as Compared to December 31, 2005

Operating Revenues. The decrease was driven primarily by the deconsolidation of Crescent effective September 7, 2006, as well as a $272 million decrease in residential developed lot sales, primarily due to decreased sales at the LandMar division in Florida.

Operating Expenses. The decrease was driven primarily the deconsolidation of Crescent effective September 7, 2006, as well as a $187 million decrease in the cost of residential developed lot sales as noted above and a $16 million impairment charge in 2005 related to a residential community in South Carolina (Oldfield).

Gains on Sales of Investments in Commercial and Multi-Family Real Estate. The increase was driven primarily by an $81 million gain on the sale of two office buildings at Potomac Yard in Washington, D.C. along with a $52 million land sale at Lake Keowee in northwestern South Carolina in 2006, partially offset by a $41 million land sale at Catawba Ridge in South Carolina in 2005, a $15 million gain on a land sale in Charlotte, North Carolina in 2005 and a $19 million gain on a project sale in Jacksonville, Florida in 2005.

Gains (Losses) on Sales of Other Assets and Other, net. The increase was due to an approximate $246 million pre-tax gain resulting from the sale of an effective 50% interest in Crescent (see Note 2 in the Consolidated Financial Statements, "Acquisitions and Dispositions").

Other Income and Expenses, net. The decrease is primarily due to $45 million in income related to a distribution from an interest in a portfolio of commercial office buildings in the third quarter of 2005.

EBIT. The increase was primarily due to the gain on sale of an ownership interest in Crescent, as noted above, as well as the sale of the Potomac Yard office buildings, partially offset by land and project sales in 2005 as discussed above.

Matters Impacting Future Crescent Results

In September 2006, Duke Energy closed an agreement to create a joint venture of Crescent and sold an effective 50% interest in Crescent to the MS Members. In conjunction with the formation of the Crescent JV, the joint venture, Crescent and Crescent's subsidiaries entered into a credit agreement with third party lenders under which Crescent borrowed approximately $1.21 billion, net of transaction costs, of which $1.19 billion was immediately distributed to Duke Energy. Subsequent to the sale, Duke Energy deconsolidated its investment in the Crescent JV and has accounted for the investment under the equity method of accounting. The combination of Duke Energy's reduction in ownership and the increased interest expense at Crescent JV as a result of the debt transaction, the impacts of which will be reflected in Duke Energy's future equity earnings, will likely significantly impact the amount of equity earnings of the Crescent JV that Duke Energy will recognize in future periods. Since the Crescent JV will capitalize interest as a component of project costs, the impacts of the interest expense on Duke Energy's equity earnings will be recognized as projects are sold by the Crescent JV.

Year Ended December 31, 2005 as Compared to December 31, 2004

Operating Revenues. The increase was driven primarily by a $64 million increase in residential developed lot sales, due to increased sales at the Palmetto Bluff project in Bluffton, South Carolina and the LandMar affiliate in Northeastern and Central Florida.

Operating Expenses. The increase was driven primarily by a $30 million increase in the cost of residential developed lot sales, due to increased developed lot sales at the projects noted above along with an $11 million increase in corporate administrative expense as a result of increased incentive compensation tied to increased operating results. The increases were offset by a $16 million impairment charge in 2005 related to the Oldfield residential project near Beaufort, South Carolina as compared to $50 million in impairment and bad debt charges in 2004 related to the Twin Creeks residential project in Austin, Texas and The Rim project in Payson, Arizona.

Gains on Sales of Investments in Commercial and Multi-Family Real Estate. The decrease was driven primarily by:

- A $37 million decrease in real estate land sales primarily due to the $45 million gain on the sale of the Alexandria tract in the Washington, D.C. area in 2004, and
- A $33 million decrease in commercial project sales primarily due to the $20 million gain on the sale of a commercial project in the Washington, D.C. area in 2004.

Partially offsetting these decreases were;

- A $37 million increase in multi-family sales primarily due to the $15 million gain on a land sale in Charlotte, North Carolina and a $19 million gain on a project sale in Jacksonville, Florida in 2005, and
- A $32 million increase in surplus land sales primarily due to a $42 million gain from a large land sale in Lancaster County, South Carolina in 2005.

Other Income and Expenses, net. The increase was primarily due to $45 million in income related to a distribution from an interest in a portfolio of commercial office buildings in the third quarter of 2005.

Minority Interest Expense. The increase in minority interest (benefit) expense is primarily due to increased earnings from the LandMar affiliate.

EBIT. The increase was primarily due to income related to a distribution from an interest in a portfolio of commercial office buildings, a large land sale in Lancaster County, South Carolina, increased multi-family and residential developed lot sales offset by a decrease in commercial land and project sales due primarily to the sale of a commercial project and the Alexandria tract in the Washington, D.C. area in 2004.

Supplemental Data

Below is supplemental information for Crescent operating results subsequent to deconsolidation on September 7, 2006:

	September 7 through December 31, 2006
	(in millions)
Operating revenues	$ 179
Operating expenses	$ 152
Operating income	$ 27
Net income	$ 30

Other

	Years Ended December 31,				
	2006	2005	Variance 2006 vs 2005	2004	Variance 2005 vs 2004
			(in millions)		
Operating revenues	$ 142	$ 72	$ 70	$ 191	$ (119)
Operating expenses	735	556	179	388	168
Gains (losses) on sales of other assets and other, net	8	8	—	(76)	84
Operating income	(585)	(476)	(109)	(273)	(203)
Other income and expenses, net	(5)	(39)	34	41	(80)
Minority interest expense (benefit)	(9)	3	(12)	(25)	28
EBIT	$(581)	$(518)	$ (63)	$(207)	$ (311)

Year Ended December 31, 2006 as Compared to December 31, 2005

Operating Revenues. The increase was driven primarily by:

- An approximate $130 million increase as a result of the prior year impact of realized and unrealized mark-to-market losses on certain discontinued cash flow hedges originally entered into to hedge Field Services' commodity price risk which were accounted for as Operating Revenues prior to the deconsolidation of DEFS, effective July 1, 2005

Partially offsetting this increase was:

- A $43 million decrease due to the sale of Duke Project Services Group, Inc. (DPSG) in February 2006, and
- A $21 million decrease due to a prior year mark-to-market gain related to former DENA's hedge discontinuance in the Southeast.

Operating Expenses. The increase was driven primarily by:

- A $128 million increase due to costs-to-achieve in 2006 related to the Cinergy merger
- A $65 million increase due to a charge in 2006 related to contract settlement negotiations
- A $58 million increase due to costs-to-achieve in 2006 related to the spin-off of Duke Energy's natural gas businesses, and
- A $14 million increase in corporate governance and other costs due primarily to the merger with Cinergy in April 2006.

Partially offsetting these increases were:

- A $47 million decrease due to the continued wind-down of the former DENA businesses, and
- A $45 million decrease due to the sale of DPSG.

Other Income and Expenses, net. The increase was driven primarily by an approximate $45 million favorable variance resulting from the realized and unrealized mark-to-market impacts associated with certain discontinued cash flow hedges originally entered into to hedge Field Services' commodity price risk which are recorded in Other income and expenses, net on the Consolidated Statements of Operations subsequent to the deconsolidation of DEFS, effective July 1, 2005.

EBIT. The decrease was due primarily to the increase in charges in 2006 associated with Cinergy merger and natural gas business spin-off costs-to-achieve, and a charge for contract settlement negotiations. These decreases were partially offset by an increase due to realized and unrealized mark-to-market impacts of certain discontinued cash flow hedges originally entered into to hedge Field Services' commodity price risk.

Matters Impacting Future Other Results

Future Other results may be subject to volatility as a result of losses insured by Bison and changes in liabilities associated with mutual insurance companies. Costs associated with achieving the spin-off of the gas business and the Cinergy merger, and the wind-down of DETM could also impact future earnings for Other.

Year Ended December 31, 2005 as Compared to December 31, 2004

Operating Revenues The decrease was driven primarily by:

- An approximate $130 million decrease as a result of the realized and unrealized mark-to-market impact of certain discontinued cash flow hedges originally entered into to hedge Field Services' commodity price risk (see Note 8 to the Consolidated Financial Statements, "Risk Management and Hedging Activities, Credit Risk, and Financial Instruments"), and
- An approximate $48 million decrease primarily due to the wind-downs of DETM and former DENA businesses

Partially offsetting these decreases was:

- A $21 million mark-to-market gain in 2005 related to former DENA's hedge discontinuance in the Southeast.

Operating Expenses. The increase was driven primarily by:

- An approximate $75 million charge to increase liabilities associated with mutual insurance companies in 2005
- A $64 million increase as a result of the 2004 correction of an immaterial accounting error in prior periods related to reserves at Bison attributable to property losses at several Duke Energy subsidiaries, and
- A $26 million increase in corporate governance costs in 2005.

Partially offsetting these increases was:

- A $35 million decrease primarily associated with the continued wind-down of DETM.

Gains (losses) on sales of other assets and other, net. The 2004 loss was due primarily to approximately $65 million ($39 million net of minority interest expense) of pre-tax losses associated with the sale and terminations of DETM contracts.

Other Income and Expenses, net. The decrease was driven primarily by an approximate $64 million decrease as a result of the realized and unrealized mark-to-market impact on discontinued hedges related to Field Services' commodity price risk (See Note 8 to the Consolidated Financial Statements, "Risk Management and Hedging Activities, Credit Risk, and Financial Instruments.")

Minority Interest Expense The change was due primarily to the continued wind-down of DETM.

EBIT. The decrease was due primarily to the realized and unrealized mark-to-market impact of certain discontinued cash flow hedges originally entered into to hedge Field Services' commodity price risk, the reversal of insurance reserves at Bison in 2004 and the increase in liabilities associated with mutual insurance companies in 2005.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The application of accounting policies and estimates is an important process that continues to evolve as Duke Energy's operations change and accounting guidance evolves. Duke Energy has identified a number of critical accounting policies and estimates that require the use of significant estimates and judgments

Management bases its estimates and judgments on historical experience and on other various assumptions that they believe are reasonable at the time of application. The estimates and judgments may change as time passes and more information about Duke Energy's environment becomes available. If estimates and judgments are different than the actual amounts recorded, adjustments are made in subsequent periods to take into consideration the new information. Duke Energy discusses its critical accounting policies and estimates and other significant accounting policies with senior members of management and the audit committee, as appropriate. Duke Energy's critical accounting policies and estimates are discussed below

Regulatory Accounting

Duke Energy accounts for certain of its regulated operations (primarily U.S. Franchised Electric and Gas and Natural Gas Transmission) under the provisions of SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation." As a result, Duke Energy records assets and liabilities that result from the regulated ratemaking process that would not be recorded under GAAP for non-regulated entities Regulatory assets generally represent incurred costs that have been deferred because such costs are probable of future recovery in customer rates Regulatory liabilities generally represent obligations to make refunds to customers for previous collections for costs that either are not likely to or have yet to be incurred. Management continually assesses whether the regulatory assets are probable of future recovery by considering factors such as applicable regulatory environment changes, recent rate orders to other regulated entities, and the status of any pending or potential deregulation legislation. Based on this continual assessment, management believes the existing regulatory assets are probable of recovery. This assessment reflects the current political and regulatory climate at the state, provincial and federal levels, and is subject to change in the future. If future recovery of costs ceases to be probable, the asset write-offs would be required to be recognized in operating income. Additionally, the regulatory agencies can provide flexibility in the manner and timing of the depreciation of property, plant and equipment, nuclear decommissioning costs and amortization of regulatory assets. Total regulatory assets were $4,072 million as of December 31, 2006 and $2,319 million as of December 31, 2005. Total regulatory liabilities were $3,058 million as of December 31, 2006 and $2,338 million as of December 31, 2005. (See Note 4 to the Consolidated Financial Statements, "Regulatory Matters.")

Long-Lived Asset Impairments and Assets Held For Sale

Duke Energy evaluates the carrying value of long-lived assets, excluding goodwill, when circumstances indicate the carrying value of those assets may not be recoverable. For long-lived assets, impairment would exist when the carrying value exceeds the sum of estimates of the undiscounted cash flows expected to result from the use and eventual disposition of the asset. If the asset is impaired, the asset's carrying value is adjusted to its estimated fair value. When alternative courses of action to recover the carrying amount of a long-lived asset are under consideration, a probability-weighted approach is used for developing estimates of future cash flows.

Duke Energy uses the best information available to estimate fair value of its long-lived assets and may use more than one source. Judgment is exercised to estimate the future cash flows, the useful lives of long-lived assets and to determine management's intent to use the assets. The sum of undiscounted cash flows is primarily dependent on forecasted commodity prices for sales of power or natural gas costs of fuel over periods of time consistent with the useful lives of the assets or changes in the real estate market. Management's intent to use or dispose of assets is subject to re-evaluation and can change over time.

A change in Duke Energy's plans regarding, or probability assessments of, holding or selling an asset could have a significant impact on the estimated future cash flows. Duke Energy considers various factors when determining if impairment tests are warranted, including but not limited to:

- Significant adverse changes in legal factors or in the business climate;
- A current-period operating or cash flow loss combined with a history of operating or cash flow losses, or a projection or forecast that demonstrates continuing losses associated with the use of a long-lived asset;
- An accumulation of costs significantly in excess of the amount originally expected for the acquisition or construction of a long-lived asset;
- Significant adverse changes in the extent or manner in which an asset is used or in its physical condition or a change in business strategy;
- A significant change in the market value of an asset; and
- A current expectation that, more likely than not, an asset will be sold or otherwise disposed of before the end of its estimated useful life.

Judgment is also involved in determining the timing of meeting the criteria for classification as an asset held for sale under SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets." (SFAS No. 144)

During 2006 and 2005, Duke Energy recorded impairments on several of its long-lived assets. (For discussion of these impairments, see Note 12 to the Consolidated Financial Statements, "Impairments, Severance and Other Charges.")

Duke Energy may dispose of certain other assets in addition to the assets classified as held for sale at December 31, 2006. Accordingly, based in part on current market conditions in the merchant energy industry, it is reasonably possible that Duke Energy's current estimate of fair value of its long-lived assets being considered for sale at December 31, 2006 and its other long-lived assets, could change and that change may impact the consolidated results of operations. In addition, Duke Energy could decide to dispose of additional assets in future periods, at prices that could be less than the book value of the assets.

Duke Energy uses the criteria in SFAS No. 144 and EITF 03-13, "Applying the Conditions in Paragraph 42 of FAS 144 in Determining Whether to Report Discontinued Operations," to determine whether components of Duke Energy that are being disposed of or are classified as held for sale are required to be reported as discontinued operations in the Consolidated Statements of Operations. To qualify as a discontinued operation under SFAS No. 144, the component being disposed of must have clearly distinguishable operations and cash flows. Additionally, pursuant to EITF 03-13, Duke Energy must not have significant continuing involvement in the operations after the disposal (i.e. Duke Energy must not have the ability to influence the operating or financial policies of the disposed component) and cash flows of the assets sold must have been eliminated from Duke Energy's ongoing operations (i.e. Duke Energy does not expect to generate significant direct cash flows from activities involving the disposed component after the disposal transaction is completed). Assuming both preceding conditions are met, the related results of operations for the current and prior periods, including any related impairments and gains or losses on sales, are reflected as (Loss) Income From Discontinued Operations, net of tax, in the Consolidated Statements of Operations. If an asset held for sale does not meet the requirements for discontinued operations classification, any impairments and gains or losses on sales are recorded in continuing operations as Gains (Losses) on Sales of Other Assets, net, in the Consolidated Statements of Operations. Impairments for all other long-lived assets, other than goodwill, are recorded as Impairments and other charges in the Consolidated Statements of Operations.

Impairment of Goodwill

At December 31, 2006 and 2005, Duke Energy had goodwill balances of $8,175 million and $3,775 million, respectively. Duke Energy evaluates the impairment of goodwill under SFAS No. 142, "Goodwill and Other Intangible Assets" (SFAS No. 142). The majority of Duke Energy's goodwill at December 31, 2006 relates to the acquisition of Cinergy in April 2006, whose assets are primarily included in the U.S. Franchised Electric and Gas and Commercial Power segments, and the acquisition of Westcoast Energy, Inc. (Westcoast) in March 2002, whose assets are primarily included within the Natural Gas Transmission segment. The remainder relates to International Energy's Latin American operations. As of the acquisition date, Duke Energy allocates goodwill to a reporting unit, which Duke Energy defines as an operating segment or one level below an operating segment. As required by SFAS No. 142, Duke Energy performs an annual goodwill impairment test and updates the test if events or circumstances occur that would more likely than not reduce the fair value of a reporting unit below its carrying amount. Key assumptions used in the analysis include, but are not limited to, the use of an appropriate discount rate, estimated future cash flows and estimated run rates of operation, maintenance, and general and administrative costs. In estimating cash flows, Duke Energy incorporates expected growth rates, regulatory stability and ability to renew contracts as well as other factors into its revenue and expense forecasts. As a result of the 2006 impairment test required by SFAS No. 142, Duke Energy did not record any impairment on its goodwill.

Management continues to remain alert for any indicators that the fair value of a reporting unit could be below book value and will assess goodwill for impairment as appropriate.

Revenue Recognition

Unbilled and Estimated Revenues. Revenues on sales of electricity, primarily at U.S. Franchised Electric and Gas, are recognized when the service is provided. Unbilled revenues are estimated by applying an average revenue/kilowatt hour for all customer classes to the number of estimated kilowatt hours delivered but not billed. Differences between actual and estimated unbilled revenues are immaterial and are a result of customer mix.

Revenues on sales of natural gas, natural gas transportation, storage and distribution as well as sales of petroleum products, primarily at Natural Gas Transmission and Field Services (prior to deconsolidation on July 1, 2005), are recognized when either the service is provided or the product is delivered. Revenues related to these services provided or products delivered but not yet billed are estimated each month. These estimates are generally based on contract data, regulatory information, estimated distribution usage based on historical data adjusted for heating degree days, commodity prices and preliminary throughput and allocation measurements. Final bills for the current month are billed and collected in the following month. Differences between actual and estimated unbilled revenues are immaterial.

Trading and Marketing Revenues. The recognition of income in the Consolidated Statements of Operations for derivative activity is primarily dependent on whether the Accrual Model or MTM Model is applied. While the MTM Model is the default method of accounting for all derivatives, SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," (SFAS No. 133) allows for the use of the Accrual Model for derivatives designated as hedges and certain scope exceptions, including the normal purchase and normal sale exception. Duke Energy designates a derivative as a hedge or a normal purchase or normal sale contract in accordance with internal hedge guidelines and the requirements provided by SFAS No. 133. (For further information regarding the Accrual Model or MTM Model, see "Risk Management Accounting" below. For further information regarding the presentation of gains and losses or revenue and expense in the Consolidated Statements of Operations, see Note 1 to the Consolidated Financial Statements, "Summary of Significant Accounting Policies".)

Risk Management Accounting

Duke Energy uses two comprehensive accounting models for its risk management activities in reporting its consolidated financial position and results of operations: the MTM Model and the Accrual Model. As further discussed in Note 1 to the Consolidated Financial Statements, "Summary of Significant Accounting Policies," the MTM Model is applied to trading and undesignated non-trading derivative contracts, and the Accrual Model is applied to derivative contracts that are accounted for as cash flow hedges, fair value hedges, and normal purchases or sales, as well as to non-derivative contracts used for commodity risk management purposes. For the three years ended December 31, 2006, the determination as to which model was appropriate was primarily based on accounting guidance issued by the Financial Accounting Standards Board (FASB) and the EITF.

Under the MTM Model, an asset or liability is recognized at fair value on the Consolidated Balance Sheets and the change in the fair value of that asset or liability is recognized in the Consolidated Statements of Operations during the current period. While former DENA was the primary business segment that used this accounting model, the U.S. Franchised Electric and Gas, Commercial Power and Field Services segments, as well as Other, have historically had certain transactions subject to this model. For the years ended December 31, 2006, 2005 and 2004, Duke Energy applied the MTM Model to its derivative contracts, unless subject to hedge accounting or the normal purchase and normal sale exemption (as described below).

The MTM Model is applied within the context of an overall valuation framework. All new and existing transactions are valued using approved valuation techniques and market data, and discounted using a risk-free based interest rate [i.e.- London Interbank Offered Rate (LIBOR) or US Treasury Rate]. When available, quoted market prices are used to measure a contract's fair value. However, market quotations for certain energy contracts may not be available for illiquid periods or locations. If no active trading market exists for a commodity or for a contract's duration, holders of these contracts must calculate fair value using internally developed valuation techniques or models. Key components used in these valuation techniques include price curves, volatility, correlation, interest rates and tenor. While volatility and correlation are the most subjective components, the price curve is generally the most significant component affecting the ultimate fair value for a contract subject to the MTM Model. Prices for illiquid periods or locations are established by extrapolating prices for correlated products, locations or periods. These relationships are routinely re-evaluated based on available market data, and changes in price relationships are reflected in price curves prospectively. Consideration may also be given to the analysis of market fundamentals when developing illiquid prices. A deviation in any of the components affecting fair value may significantly affect overall fair value.

Valuation adjustments for performance and market risk, and administration costs are used to arrive at the fair value of the contract and the gain or loss ultimately recognized in the Consolidated Statements of Operations. While Duke Energy uses common industry practices to develop its valuation techniques, changes in Duke Energy's pricing methodologies or the underlying assumptions could result in significantly different fair values and income recognition. However, due to the nature and number of variables involved in estimating fair values, and the interrelationships among these variables, sensitivity analysis of the changes in any individual variable is not considered to be relevant or meaningful.

Validation of a contract's calculated fair value is performed by an internal group independent of Duke Energy's deal origination areas. This group performs pricing model validation, back testing and stress testing of valuation techniques, prices and other variables. Validation of a contract's fair value may be done by comparison to actual market activity and negotiation of collateral requirements with third parties.

For certain derivative instruments, Duke Energy applies either hedge accounting or the normal purchase and normal sales exemption in accordance with SFAS No. 133. The use of hedge accounting and the normal purchase and normal sales exemption provide effectively for the use of the Accrual Model. Under this model, there is generally no recognition in the Consolidated Statements of Operations for changes in the fair value of a contract until the service is provided or the associated delivery period occurs (settlement).

Hedge accounting treatment may be used when Duke Energy contracts to buy or sell a commodity such as natural gas at a fixed price for future delivery corresponding with anticipated physical sales or purchase of natural gas (cash flow hedge). In addition, hedge accounting treatment may be used when Duke Energy holds firm commitments or asset positions and enters into transactions that "hedge" the risk that the price of a commodity, such as natural gas or electricity, may change between the contract's inception and the physical delivery date of the commodity (fair value hedge). To the extent that the fair value of the hedge instrument offsets the transaction being hedged, there is no impact to the Consolidated Statements of Operations prior to settlement of the hedge. However, as not all of Duke Energy's hedges relate to the exact location being hedged, a certain degree of hedge ineffectiveness may be recognized in the Consolidated Statements of Operations.

The normal purchases and normal sales exception, as provided in SFAS No. 133 as amended and interpreted by Derivative Implementation Group Issue C15, "Scope Exceptions: Normal Purchases and Normal Sales Exception for Option-Type Contracts and Forward Contracts in Electricity," (DIG Issue No. C15) and amended by SFAS No. 149, "Amendment of Statement 133 on Derivative

Instruments and Hedging Activities," (SFAS No. 149) indicates that no recognition of the contract's fair value in the Consolidated Financial Statements is required until settlement of the contract (in Duke Energy's case, the delivery of power). On a limited basis, Duke Energy applies the normal purchase and normal sales exception to certain contracts. To the extent that the hedge is perfectly effective, income statement recognition for the contract will be the same under either model.

In addition to derivative contracts that are accounted for as cash flow hedges, fair value hedges, and normal purchases or sales, the Accrual Model also encompasses non-derivative contracts used for commodity risk management purposes. For these non-derivative contracts, there is no recognition in the Consolidated Statements of Operations until the service is provided or delivery occurs.

As a result of the September 2005 decision to pursue the sale or other disposition of substantially all of former DENA's remaining assets and contracts outside the Midwestern United States, Duke Energy discontinued hedge accounting for forward natural gas and power contracts accounted for as cash flow hedges and disqualified other forward power contracts previously designated under the normal purchases normal sales exception effective September 2005.

For additional information regarding risk management activities, see "*Quantitative and Qualitative Disclosures about Market Risk*". The "Quantitative and Qualitative Disclosures about Market Risk" include daily earnings at risk information related to commodity derivatives recorded using the MTM Model and an operating income sensitivity analysis related to hypothetical changes in certain commodity prices recorded using the Accrual Model.

Pension and Other Post-Retirement Benefits

Duke Energy accounts for its defined benefit pension plans using SFAS No. 87, "*Employers' Accounting for Pensions*," (SFAS No. 87) and SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans." Under SFAS No. 87, pension income/expense is recognized on an accrual basis over employees' approximate service periods. Other post-retirement benefits are accounted for using SFAS No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions," (SFAS No. 106). (See Note 22 to the Consolidated Financial Statements, "Employee Benefit Plans.")

Funding requirements for defined benefit plans are determined by government regulations, not SFAS No. 87. Duke Energy made voluntary contributions of $124 million in 2006, zero in 2005 and $250 million in 2004 to its U.S. plan. Duke Energy anticipates making a contribution of approximately $150 million to the U.S. plan in 2007. Duke Energy made contributions to the Westcoast DB plans of approximately $44 million in 2006, $42 million in 2005 and $26 million in 2004. As a result of the spin-off of the natural gas businesses, Duke Energy has no future obligations to make contributions to the Westcoast DB plans. Duke Energy made contributions to the Westcoast DC plans of approximately $4 million in 2006, $3 million in 2005 and $3 million in 2004. As a result of the spin-off of the natural gas businesses, Duke Energy has no future obligations to make contributions to the Westcoast DC plans.

The calculation of pension expense, other post-retirement expense and Duke Energy's pension and other post-retirement liabilities require the use of assumptions. Changes in these assumptions can result in different expense and reported liability amounts, and future actual experience can differ from the assumptions. Duke Energy believes that the most critical assumptions for pension and other post-retirement benefits are the expected long-term rate of return on plan assets and the assumed discount rate. Additionally, medical and prescription drug cost trend rate assumptions are critical for other post-retirement benefits. The prescription drug trend rate assumption resulted from the effect of the Medicare Prescription Drug Improvement and Modernization Act (Modernization Act).

Duke Energy U.S. Plans

Duke Energy and its subsidiaries (including legacy Cinergy businesses) maintain non-contributory defined benefit retirement plans (U.S. Plans). The U.S. Plans cover most U.S. employees using a cash balance formula. Under a cash balance formula, a plan participant accumulates a retirement benefit consisting of pay credits that are based upon a percentage (which may vary with age and years of service) of current eligible earnings and current interest credits. Certain legacy Cinergy U.S. employees are covered under plans that use a final average earnings formula. Under a final average earnings formula, a plan participant accumulates a retirement benefit equal to a percentage of their highest 3-year average earnings, plus a percentage of their highest 3-year average earnings in excess of covered compensation per year of participation (maximum of 35 years), plus a percentage of their highest 3-year average earnings times years of participation in excess of 35 years. Duke Energy also maintains non-qualified, non-contributory defined benefit retirement plans which cover certain U.S. executives.

Duke Energy and most of its subsidiaries also provide some health care and life insurance benefits for retired employees on a contributory and non-contributory basis. Employees are eligible for these benefits if they have met age and service requirements at retirement, as defined in the plans.

Duke Energy's U S Plans recognized pre-tax pension cost of $80 million, pre-tax non-qualified pension cost of $11 million and pre-tax other post-retirement benefits cost of $76 million in 2006 In 2007, Duke Energy's U.S. pension cost is expected to be approximately $5 million lower, non-qualified pension cost is expected to be $1 million lower and other post-retirement benefits cost is expected to be $16 million lower primarily as a result of the spin-off of the natural gas businesses.

For both pension and other post-retirement plans, Duke Energy assumed that its U.S. plan's assets would generate a long-term rate of return of 8.5% as of September 30, 2006. The assets for Duke Energy's U.S. pension and other post-retirement plans are maintained by a master trust. The investment objective of the master trust is to achieve reasonable returns on trust assets, subject to a prudent level of portfolio risk, for the purpose of enhancing the security of benefits for plan participants. The asset allocation target was set after considering the investment objective and the risk profile with respect to the trust. U.S. equities are held for their high expected return. Non-U.S. equities, debt securities, and real estate are held for diversification. Investments within asset classes are to be diversified to achieve broad market participation and reduce the impact of individual managers or investments. Duke Energy regularly reviews its actual asset allocation and periodically rebalances its investments to its targeted allocation when considered appropriate.

The expected long-term rate of return of 8.5% for the Duke Energy U.S. assets was developed using a weighted average calculation of expected returns based primarily on future expected returns across asset classes considering the use of active asset managers. The weighted average returns expected by asset classes were 4.2% for U.S. equities, 1.8% for Non U.S. equities, 2.2% for fixed income securities, and 0.3% for real estate.

If Duke Energy had used a long-term rate of 8.25% in 2006, pre-tax pension expense would have been higher by approximately $8 million and pre-tax other post-retirement expense would have been higher by approximately $1 million. If Duke Energy had used a long-term rate of 8.75% pre-tax pension expense would have been lower by approximately $8 million and pre-tax other post-retirement expense would have been lower by approximately $1 million.

Duke Energy discounted its future U.S. pension and other post-retirement obligations using a rate of 5.75% as of September 30, 2006. Duke Energy discounted its future U.S. pension and other post-retirement obligations using rates of 5.50% as of September 30, 2005 for its non-legacy Cinergy business pension plans and 6.00% as of April 1, 2006 for its legacy Cinergy business pension plans. For legacy Cinergy plans, the discount rate reflects remeasurement as of April 1, 2006 due to the merger between Duke Energy and Cinergy. Duke Energy determines the appropriate discount based on a AA bond yield curve. The yield is selected based on bonds with cash flows that match the timing and amount of the expected benefit payments under the plan. Lowering the discount rates by 0.25% would have decreased Duke Energy's 2006 pre-tax pension expense by approximately $2 million. Increasing the discount rates by 0.25% would have increased Duke Energy's 2006 pre-tax pension expense by approximately $2 million. Lowering the discount rates by 0.25% would have increased Duke Energy's 2006 pre-tax other post-retirement expense by approximately $1 million. Increasing the discount rate by 0.25% would have decreased Duke Energy's 2006 pre-tax other post-retirement expense by approximately $1 million.

Duke Energy's U.S. post-retirement plan uses a medical care trend rate which reflects the near and long-term expectation of increases in medical health care costs. Duke Energy's U.S. post-retirement plan uses a prescription drug trend rate which reflects the near and long-term expectation of increases in prescription drug health care costs. As of September 30, 2006, the medical care trend rates were 8.50%, which grades to 4.75% by 2013. As of September 30, 2006, the prescription drug trend rate was 13.00%, which grades to 4.75% by 2022. If Duke Energy had used health care trend rates one percentage point higher, pre-tax other post-retirement expense would have been higher by $6 million. If Duke Energy had used health care trend rates one percentage point lower, pre-tax other post-retirement expense would have been lower by $5 million.

Future changes in plan asset returns, assumed discount rates and various other factors related to the participants in Duke Energy's pension and post-retirement plans will impact Duke Energy's future pension expense and liabilities. Management cannot predict with certainty what these factors will be in the future.

Westcoast Plans

Westcoast and its subsidiaries maintain contributory and non-contributory defined benefit (DB) and defined contribution (DC) retirement plans covering substantially all employees. The DB plans provide retirement benefits based on each plan participant's years of service and final average earnings. Under the DC plans, company contributions are determined according to the terms of the plan and based on each plan participant's age, years of service and current eligible earnings. Westcoast also provides health care and life insurance benefits for retired employees on a non-contributory basis. Employees are eligible for these benefits if they have met age and service requirements at retirement, as defined in the plans. Effective December 31, 2003, a new plan was implemented for all non bargaining employees and the majority of bargaining employees. The new plan applied to employees retiring on and after January 1, 2006. The new plan is predominantly a defined contribution plan as compared to the existing defined benefit program.

Westcoast recognized pre-tax pension cost of $22 million, pre-tax non-qualified pension cost of $6 million and pre-tax other post-retirement benefits cost of $12 million in 2006. In 2007, As a result of the spin-off of the natural gas businesses, Duke Energy will not incur any future pension costs associated with the Westcoast plan.

The expected long-term rate of return for the Westcoast plans assets was 7.25% as of September 30, 2006. The Westcoast plans assets for registered pension plans are maintained by a master trust. The investment objective of the master trust is to achieve reasonable returns on trust assets, subject to a prudent level of portfolio risk, for the purpose of enhancing the security of benefits for plan participants. The asset allocation target was set after considering the investment objective and the risk profile with respect to the trust. Canadian equities are held for their high expected return. Non-Canadian equities are held for their high expected return as well as diversification relative to Canadian equities and debt securities. Debt securities are also held for diversification.

The expected long-term rate of return of 7.25% and 7.50% as of September 30, 2006 and 2005, respectively, for the Westcoast assets was developed using a weighted average calculation of expected returns based primarily on future expected returns across asset classes considering the use of active asset managers. The weighted average returns expected by asset classes were 2.5% for Canadian equities, 1.3% for U.S. equities, 1.4% for Europe, Australasia and Far East equities, and 2.0% for fixed income securities. For 2006, the expected long-term rate of return used to calculate pension expense was 7.5%. Lowering the expected rate of return on assets by 0.25% (from 7.50% to 7.25%) would have increased Westcoast's 2006 pre-tax pension expense by approximately $1 million. Increasing the expected rate of return by 0.25% (from 7.50% to 7.75%) would have decreased Westcoast's 2006 pre-tax pension expense by approximately $1 million. The Westcoast other post-retirement plan does not hold any assets.

Westcoast discounted its future pension and other post-retirement obligations using a rate of 5.00% as of September 30, 2006 and 2005. For Westcoast, the discount rate used to determine the pension and other post-retirement obligations is prescribed as the yield on Canadian corporate AA bonds at the measurement date of September 30. The yield is selected based on bonds with cash flows that match the timing and amount of the expected benefit payments under the plan. For 2006, the discount rate used to calculate pension expense was 5.00%. Lowering the discount rate by 0.25% (from 5.00% to 4.75%) would have increased Duke Energy's 2006 pre-tax pension expense by approximately $2 million. Increasing the discount rate by 0.25% (from 5.00% to 5.25%) would have decreased Duke Energy's 2006 pre-tax pension expense by approximately $2 million. Lowering the discount rate by 0.25% (from 5.00% to 4.75%) would have increased Duke Energy's 2006 pre-tax other post-retirement expense by approximately $1 million. Increasing the discount rate by 0.25% (from 5.00% to 5.25%) would have decreased Duke Energy's 2006 pre-tax other post-retirement expense by approximately $1 million.

The Westcoast post-retirement plans use a medical care trend rate which reflects the near and long-term expectation of increases in medical costs. As of September 30, 2006, the health care trend rates were 8.00%, which grades to 5.00% by 2009. If Westcoast had used a health care trend rate one percentage point higher, pre-tax other post-retirement expense would have been higher by $2 million. If Westcoast had used a health care trend rate one percentage point lower, pre-tax other post-retirement expense would have been lower by less than $1 million.

LIQUIDITY AND CAPITAL RESOURCES

Known Trends and Uncertainties

Duke Energy will rely primarily upon cash flows from operations, as well as its cash, cash equivalents and short-term investments to fund its liquidity and capital requirements for 2007. The current cash, cash equivalents and short-term investments and future cash generated from operations may be used by Duke Energy to continue with its February 2005 announced plan to periodically repurchase up to an aggregate of $2.5 billion of common stock over a three year period. In June 2006, the share repurchase plan was suspended. At the time of the suspension of the repurchase plan, Duke Energy had repurchased approximately 50 million shares of common stock for approximately $1.4 billion since inception of the repurchase plan. In October 2006, Duke Energy's Board of Directors authorized the reactivation of the share repurchase plan for Duke Energy of up to $500 million of share repurchases after the spin-off of the natural gas businesses. In addition, Duke Energy's future cash flows will be negatively impacted by the spin-off of the natural gas businesses effective January 2, 2007. For the year ended December 31, 2006, operating, investing and financing cash flows provided/(used) by the natural gas businesses, including distributions from Duke Energy's 50% investment in DEFS, were approximately $1.7 billion, $(0.6) billion and $(0.2) billion, respectively.

A material adverse change in operations or available financing may impact Duke Energy's ability to fund its current liquidity and capital resource requirements.

Duke Energy currently anticipates net cash provided by operating activities in 2007 to be lower than in 2006, primarily as a result of the following:

- Lower operating cash flows as a result of the spin-off of the natural gas businesses, as discussed above; and,

- Lower operating cash flows due to the sale of an effective 50% interest in the Crescent JV in September 2006.

These lower operating cash flows are expected to be partially offset by the following:

- Lower costs incurred related to the merger with Cinergy; and,

- Higher operating results of legacy Cinergy businesses as a result of ownership for the entire year 2007.

Additionally, Duke Energy anticipates funding its defined benefit pension plans with approximately $150 million of cash during 2007, as compared to $172 million during 2006.

Ultimate cash flows from operations are subject to a number of factors, including, but not limited to, regulatory constraints, economic trends, and market volatility (see Item 1A "Risk Factors" for details).

Duke Energy projects 2007 capital and investment expenditures of approximately $3.3 billion, primarily consisting of approximately:

- $2.8 billion at U.S. Franchised Electric and Gas, including $0.4 billion of North Carolina Clean Air Expenditures

- $0.3 billion at Commercial Power

- $0.2 billion combined at International Energy and Other

Duke Energy continues to focus on reducing risk and restructuring its business for future success and will invest principally in its strongest business sectors with an overall focus on positive net cash generation. Based on this goal, approximately 85 percent of total projected 2007 capital expenditures are allocated to the U.S. Franchised Electric and Gas segment. Total U.S. Franchised Electric and Gas projected 2007 capital and investment expenditures include approximately $1.5 billion for maintenance and upgrades of existing plants and infrastructure to serve load growth, approximately $0.7 billion of environmental expenditures, and approximately $0.6 billion of expansion capital. Duke Energy's U.S. Franchised Electric and Gas business segment is evaluating the construction of several large, new electric generating plants in North Carolina, South Carolina, and Indiana. During this evaluation process, Duke Energy has begun to see significant increases in the estimated costs of these projects driven by strong domestic and international demand for the material, equipment, and labor necessary to construct these facilities. In October 2006, Duke Energy made a filing with the NCUC related to the Duke Energy Carolinas' request for a CPCN for the Cliffside project. In this filing, Duke Energy stated that due to the rising costs described above, the cost of building the Cliffside units could be approximately $3 billion, excluding AFUDC. The costs described above are expected to continue to increase causing the overall cost of the Cliffside project to increase, until such time as the NCUC issues a CPCN and Duke Energy is able to enter into definitive agreements with necessary material and service providers. On February 28, 2007, the NCUC issued a notice of decision approving the construction of one unit at the Cliffside Steam Station. The NCUC stated that it will issue a full order in the near future. Duke Energy will review the NCUC's order, once issued, and determine whether to proceed with the Cliffside Project or consider other alternatives, including additional gas fired generation. Duke Energy is attempting to obtain approval for the upfront recovery of development costs related to a proposed nuclear power plant. Duke Energy does not anticipate beginning construction of the proposed nuclear power plant without adequate assurance of cost recovery from the state regulators. In November 2006, Duke Energy received approval for nearly $260 million of future federal tax credits related to costs to be incurred for the modernization of the Cliffside facility as well as the Integrated Gasification on Combined Cycle (IGCC) plant in Indiana.

Duke Energy Indiana's estimated costs associated with the potential construction of an IGCC plant in Indiana have also increased. Duke Energy Indiana's publicly filed testimony with the Indiana Utility Regulatory Commission indicates that industry (EPRI) total capital requirement estimates for a facility of this type and size are now in the range of $1.6 billion to $2.1 billion (including escalation to 2011 and owner's specific site costs).

Duke Energy anticipates its debt to total capitalization ratio to be approximately 38% by the end of 2007, as compared to 43% at the end of 2006. This reduction is primarily due to the impacts of the spin-off the natural gas businesses in 2007. Duke Energy does not expect its total debt balance (including outstanding commercial paper balances) to change significantly in 2007, excluding the impacts of approximately $8.6 billion of debt transferred to Spectra Energy as a result of the spin-off of the natural gas businesses.

Excluding the debt which was transferred in connection with the spin-off of the natural gas businesses on January 2, 2007, Duke Energy has expected debt maturities of approximately $1.1 billion in 2007. Duke Energy expects to refinance approximately $0.5 billion of these maturities. Based upon anticipated 2007 cash flows from operations and capital expenditure and dividend payment plans, Duke Energy expects to increase outstanding commercial paper balances by approximately $0.6 billion during 2007. Current total available capacity under Duke Energy's commercial paper facilities is sufficient to meet these additional requirements.

Duke Energy monitors compliance with all debt covenants and restrictions, and does not currently believe that it will be in violation or breach of its debt covenants. However, circumstances could arise that may alter that view. If and when management had a belief that such potential breach could exist, appropriate action would be taken to mitigate any such issue. Duke Energy also maintains an active dialogue with the credit rating agencies, and believes that the current credit ratings are positioned for potential improvement evidenced by positive outlooks at Duke Energy and most of its subsidiaries.

Operating Cash Flows

Net cash provided by operating activities was $3,748 million in 2006 compared to $2,818 million in 2005, an increase of $930 million. The increase in cash provided by operating activities was due primarily to the following:

- The impacts of the merger with Cinergy, effective April 3, 2006,
- Collateral received by Duke Energy (approximately $540 million) in 2006 from Barclays, partially offset by
- The settlement of the payable to Barclays (approximately $600 million) in 2006, and
- An approximate $400 million decrease in 2006 due to the net settlement of the remaining DENA contracts.

Net cash provided by operating activities was $2,818 million in 2005 compared to $4,168 million in 2004, a decrease of $1,350 million. The decrease in cash provided by operating activities was due primarily to the following:

- Approximately $750 million of additional net cash collateral posted by Duke Energy during 2005 attributable to increased crude oil prices, as well as increases to the forward market prices of power,
- An approximate $900 million increase in taxes paid, net of refunds, in 2005, and,
- The impacts of the deconsolidation of DEFS effective July 1, 2005.

These decreases were offset by an increase in cash provided due to an approximate $234 million decrease in contributions to company-sponsored pension plans in 2005.

Investing Cash Flows

Net cash used in investing activities was $1,328 million in 2006 compared to $126 million in 2005, an increase in cash used of $1,202 million. Net cash used in investing activities was $126 million in 2005 compared to $793 million in 2004, a decrease in cash used of $667 million.

The primary use of cash related to investing activities is capital and investment expenditures, detailed by business segment in the following table.

Capital and Investment Expenditures by Business Segment

	Years Ended December 31,		
	2006	2005	2004
	(in millions)		
U.S. Franchised Electric and Gas[(a)]	$2,381	$1,350	$1,126
Natural Gas Transmission	790	930	544
Field Services[(b)]	—	86	202
Commercial Power	209	2	7
International Energy	58	23	28
Crescent[(c)(d)]	507	599	568
Other	131	29	54
Total consolidated	$4,076	$3,019	$2,529

(a) Amounts include capital expenditures associated with North Carolina clean-air legislation of $403 million in 2006, $310 million in 2005 and $106 million in 2004 which are included in Capital Expenditures within Cash Flows from Investing Activities on the accompanying Consolidated Statements of Cash Flows.

(b) As a result of the deconsolidation of DEFS, effective July 1, 2005, Field Services amounts for 2005 only include DEFS capital and investment expenditures for periods prior to July 1, 2005.

(c) Amounts include capital expenditures associated with residential real estate of $322 million for the period from January 1, 2006 through the date of deconsolidation (September 7, 2006), $355 million in 2005, and $322 million in 2004 which are included in Capital Expenditures for Residential Real Estate within Cash Flows from Operating Activities on the accompanying Consolidated Statements of Cash Flows.

(d) As a result of the deconsolidation of Crescent, effective September 7, 2006, Crescent amounts for 2006 only include Crescent capital and investment expenditures for periods prior to September 7, 2006.

The increase in cash used in investing activities in 2006 as compared to 2005 is primarily due to the following:

- Increased capital and investment expenditures of $1,090 million, excluding Crescent's residential real estate investment, primarily as a result of capital expenditures at U.S. Franchised Electric and Gas, primarily due to the acquisition of Cinergy in April 2006, the acquisition of the Rockingham facility in 2006 and increased expenditures associated with North Carolina clean-air legislation; and,

- Increased purchases of short-term investments of approximately $900 million in 2006 as compared to 2005, due primarily to the proceeds from the Crescent debt financing.

These increases were partially offset by the following:

- An increase in proceeds received from asset sales in 2006 as compared to 2005. Asset sales activity in 2006 of approximately $2.9 billion primarily involved the disposal of the former DENA operations outside of the Midwestern United States, Cinergy's commercial marketing and trading business operations, as well as the Crescent JV transaction. Asset sales activity in 2005 of approximately $2.4 billion primarily involved the disposition of the investments in TEPPCO as well as the DEFS disposition transaction.

The decrease in cash used in investing activities in 2005 as compared to 2004 is primarily due to the following:

- An increase in proceeds from the sale of assets in 2005 as compared to 2004. Asset sales activity in 2005 of approximately $2.4 billion primarily involved the disposition of the investments in TEPPCO as well as the DEFS disposition transaction. Asset sales activity in 2004 of approximately $1.6 billion primarily involved the sales of the Asia-Pacific Business, Southeast Plants and Moapa and Luna partially completed facilities; and,

- Decreased amounts of cash invested in short-term investments in 2005 as compared to 2004.

These decreases were partially offset by the following:

- Increased capital and investment expenditures, excluding Crescent's residential real estate investments, of $460 million primarily as a result of the approximate $230 million acquisition of the Empress System at Natural Gas Transmission and an increase in expenditures associated with North Carolina clean-air legislation.

Financing Cash Flows and Liquidity

Duke Energy's consolidated capital structure as of December 31, 2006, including short-term debt, was 43% debt, 55% common equity and 2% minority interests. The fixed charges coverage ratio, calculated using SEC guidelines, was 3.2 times for 2006, which includes a pre-tax gain of approximately $250 million on the sale of an effective 50% interest in Crescent, 4.7 times for 2005, which includes a pre-tax gain on the sale of TEPPCO GP and LP of approximately $0.9 billion, net of minority interest, and 2.3 times for 2004.

Net cash used in financing activities was $1,961 million in 2006 compared to $2,717 million in 2005, a decrease of $756 million. The change was due primarily to the following:

- An approximate $1.1 billion increase in proceeds from the issuance of long-term debt in 2006, net of redemptions, due primarily to the approximate $1.2 billion of debt proceeds from the Crescent JV transaction, and

- An approximate $400 million decrease in share repurchases under Duke Energy's share repurchase plan.

These increases were partially offset by:

- An approximate $400 million increase in dividends paid due to the increase in the quarterly dividend paid per share combined with a larger number of shares outstanding, primarily attributable to the 313 million shares issued in connection with the Cinergy merger, and

- The repayment of approximately $400 million of notes payable and commercial paper in 2006 due primarily to proceeds received from asset sales.

Net cash used in financing activities was $2,717 million in 2005 compared to $3,278 million in 2004, a decrease of $561 million. The change was due primarily to the following:

- Approximately $3.0 billion of lower redemptions, net of paydowns, of long-term debt, commercial paper, notes payable, preferred and preference stock, and preferred stock of a subsidiary during 2005 as compared to 2004 as a result of an effort to reduce debt balances in 2004.

This decrease was partially offset by:

- Approximately $2.6 billion of lower proceeds from common stock transactions during 2005, primarily driven by the settlement of the forward purchase contract component of Duke Energy's Equity Units in May and November 2004 for total proceeds of $1.7 billion and the repurchase of 32.6 million shares of common stock for $933 million in 2005.

With cash, cash equivalents and short-term investments on hand at December 31, 2006 of approximately $2.5 billion and a more stable portfolio of businesses, Duke Energy has financial flexibility to buy back common stock, invest incrementally or pay down additional debt. Duke Energy is evaluating these options and will determine the best economic decision to meet the needs of shareholders and the long-term financial strength of Duke Energy.

Significant Financing Activities—Year Ended 2006. During the year ended December 31, 2006, Duke Energy's consolidated credit capacity increased by approximately $842 million, primarily due to the merger with Cinergy. This increase was net of other reductions in credit capacity due to the terminations of an $800 million syndicated credit facility and $590 million of other bi-lateral credit facilities The terminations of these credit facilities primarily reflect Duke Energy's reduced liquidity needs as a result of exiting the former DENA business

During the year ended December 31, 2006, Duke Energy increased the portion of outstanding commercial paper and pollution control bond balances classified as long-term from $472 million to $929 million. This non-current classification is due to the existence of long-term credit facilities which back-stop these balances along with Duke Energy's intent to refinance such balances on a long-term basis.

During 2006, Duke Energy has repurchased approximately 17 5 million shares of its common stock for approximately $500 million

In November 2006, Union Gas issued 4 85% fixed-rate debenture bonds denominated in 125 million Canadian dollars (approximately $108 million U S. dollar equivalents as of the closing date) due in 2022.

In October 2006, Duke Energy Carolinas issued $150 million in tax-exempt floating-rate bonds. The bonds are structured as variable-rate demand bonds, subject to weekly remarketing and bear a final maturity of 2031 The initial interest rate was set at 3 72%. The bonds are supported by an irrevocable 3-year direct-pay letter of credit and were issued through the North Carolina Capital Facilities Finance Agency to fund a portion of the environmental capital expenditures at the Marshall and Belews Creek Steam Stations.

During October 2006, the $130 million bi-lateral credit facility at Spectra Energy Capital was cancelled. In addition, the remaining $120 million bi-lateral credit facility was cancelled in November 2006 and reissued at Duke Energy for the same amount with the same terms and conditions.

In September 2006, prior to the completion of the partial sale of Crescent to the MS Members as discussed in Note 2 to the Consolidated Financial Statements, "Acquisitions and Dispositions," Crescent issued approximately $1 23 billion principal amount of debt. The net proceeds from the debt issuance of approximately $1 21 billion were recorded as a Financing Activity on the Consolidated Statements of Cash Flows. As a result of Duke Energy's deconsolidation of Crescent effective September 7, 2006, Crescent's outstanding debt balance of $1,298 million was removed from Duke Energy's Consolidated Balance Sheets

In September 2006, Union Gas entered into a fixed-rate financing agreement denominated in 165 million Canadian dollars (approximately $148 million in U S. dollar equivalents as of the issuance date) due in 2036 with an interest rate of 5 46%.

In September 2006, the Income Fund sold approximately 9 million previously unissued Trust Units at a price of 12.15 Canadian dollars per Trust Unit for total proceeds of 104 million Canadian dollars, net of commissions and expenses of other expenses of issuance. The sale of approximately 9 million Trust Units reduced Duke Energy's ownership interest in the Income Fund to approximately 46% at December 31, 2006. As a result of the sale of additional Trust Units, Duke Energy recognized an approximate $15 million U S. Dollar pre-tax SAB No 51 gain on the sale of subsidiary stock. The proceeds from the offering plus the draw down of approximately 39 million Canadian dollars on an available credit facility were used by the Income Fund to acquire a 100% interest in Westcoast Gas Services, Inc. Subsequent to this transaction, Duke Energy had an approximate 46% ownership interest in the Income Fund.

In August 2006, Duke Energy Kentucky issued approximately $77 million principal amount of floating rate tax-exempt notes due August 1, 2027. Proceeds from the issuance were used to refund a like amount of debt on September 1, 2006 then outstanding at Duke Energy Ohio Approximately $27 million of the floating rate debt was swapped to a fixed rate concurrent with closing.

In June 2006, Duke Energy Indiana issued $325 million principal amount of 6.05% senior unsecured notes due June 15, 2016. Proceeds from the issuance were used to repay $325 million of 6 65% First Mortgage Bonds that matured on June 15, 2006.

During the second, third and fourth quarters of 2006, Duke Energy's $742 million of convertible debt became convertible into approximately 31.7 million shares of Duke Energy common stock due to the market price of Duke Energy common stock achieving a specified threshold during each respective quarter. Holders of the convertible debt were able to exercise their right to convert on or prior to each quarter end. During the second and third quarters, approximately $632 million of debt was converted into approximately 26.7 million shares of Duke Energy Common Stock At December 31, 2006, the balance of the convertible debt is approximately $110 million

Significant Financing Activities—Year Ended 2005. In connection with the up to $2 5 billion share repurchase program announced in February 2005, Duke Energy entered into an accelerated share repurchase transaction. Duke Energy repurchased and retired 30 million shares of its common stock from an investment bank at the March 18, 2005 closing price of $27.46 per share (total of approximately $834 million, including approximately $10 million in commissions and other fees). The final settlement with the investment bank occurred on September 22, 2005 for approximately $25 million in cash. The final settlement price was the difference between the initial settlement price of $27.46 per share and the volume weighted average price per share of actual shares purchased by the investment bank of $28 42 per share Duke Energy also entered into a separate open-market purchase plan with the investment bank on March 18, 2005 to repurchase up to an additional 20 million shares of its common stock through December 27, 2005. As of May 9, 2005 (the date Duke and Cinergy announced a merger agreement), Duke Energy had already repurchased 2.6 million shares of its common stock through the separate open-market purchase plan at a weighted average price of $28.97 per share. In May 2005, in connection with the anticipated merger with Cinergy, Duke Energy suspended additional repurchases under the open market purchase plan. For the year ended December 31, 2005 a total of 32.6 million shares of common stock were repurchased under both share repurchase programs for approximately $933 million.

In December 2005, the Income Fund, a Canadian income trust fund, was created which sold approximately 40% ownership in the Canadian Midstream operations for proceeds, net of underwriting discount, of approximately $110 million. In January 2006, a subsequent greenshoe sale of additional ownership interests, pursuant to an overallotment option, in the Income Fund were sold for approximately $10 million.

In November 2005, International Energy issued floating rate debt in Guatemala for $87 million (in USD) and in El Salvador for $75 million (in USD). These debt issuances have variable interest rate terms and mature in 2015.

On September 21, 2005, Union Gas entered into a fixed-rate financing agreement denominated in 200 million Canadian dollars (approximately $171 million in U.S. dollar equivalents as of the issuance date) due in 2016 with an interest rate of 4.64%.

In August 2005, DEI issued project-level debt in Peru, of which $75 million is denominated in U.S. dollars and approximately $34 million (in U.S. dollar equivalents as of the issuance date) is denominated in Peru Nuevos Soles. This debt has terms ranging from four to six years as well as variable or fixed interest rate terms, as applicable.

On March 1, 2005, redemption notices were sent to the bondholders of the $100 million PanEnergy 8.625% bonds due in 2025. These bonds were redeemed on April 15, 2005 at a redemption price of 104.03 or approximately $104 million.

During the first quarter of 2005, Duke Energy increased the portion of outstanding commercial paper balances classified as long-term debt from $150 million to $300 million. This non-current classification is due to the existence of long-term credit facilities which back-stop these commercial paper balances along with Duke Energy's intent to refinance such balances on a long-term basis.

In December 2004, Duke Energy reached an agreement to sell its partially completed Gray's Harbor power generation facility (Grays Harbor) to an affiliate of Invenergy LLC. In 2004, Duke Energy terminated its capital lease with the dedicated pipeline which would have transported natural gas to Grays Harbor. As a result of this termination, approximately $94 million was paid by Duke Energy in January 2005.

Preferred and Preference Stock of Duke Energy. In December 2005, Duke Energy redeemed all Preferred and Preference stock without Sinking Fund Requirements for approximately $137 million and recognized an immaterial loss on the redemption.

Available Credit Facilities and Restrictive Debt Covenants. Duke Energy's credit agreements contain various financial and other covenants. Failure to meet those covenants beyond applicable grace periods could result in accelerated due dates and/or termination of the agreements. As of December 31, 2006, Duke Energy was in compliance with those covenants. In addition, some credit agreements may allow for acceleration of payments or termination of the agreements due to nonpayment, or to the acceleration of other significant indebtedness of the borrower or some of its subsidiaries. None of the debt or credit agreements contain material adverse change clauses.

(For information on Duke Energy's credit facilities as of December 31, 2006, see Note 15 to the Consolidated Financial Statements, "Debt and Credit Facilities.")

Credit Ratings. Duke Energy and certain subsidiaries each hold credit ratings by Standard & Poor's (S&P) and Moody's Investors Service (Moody's). In addition, certain subsidiaries transferred to Spectra Energy hold credit ratings by DBRS (formerly Dominion Bond Rating Service). Actions taken by ratings agencies subsequent to January 2, 2007 related to businesses transferred to Spectra Energy are not reflected herein since such actions have no impact on the ongoing operations of Duke Energy post spin-off.

In May 2006, S&P changed the outlook of Duke Energy and all of its subsidiaries (with the exception of Maritimes & Northeast Pipeline, LLC and Maritimes & Northeast Pipeline, LP (collectively M&N Pipeline) and DETM from stable to positive reflecting Duke Energy's announcement to sell Cinergy's commercial trading and marketing operations.

In April 2006, following the completion of Duke Energy's merger with Cinergy, S&P removed Cinergy and its subsidiaries from credit-watch negative where they had been placed in May 2005 following the Cinergy merger announcement. S&P lowered Cinergy's Corporate Credit Rating (CCR) consistent with Duke Energy's CCR as disclosed in the table below. As a result of Cinergy's lower CCR, S&P lowered the senior unsecured credit rating of Cinergy Corp. reflecting the structural subordination of its debt. In addition, S&P reassessed its view of the structural subordination for the debt outstanding at Spectra Energy Capital, Duke Energy Ohio, Duke Energy Indiana, and Duke Energy Kentucky and assigned the senior unsecured credit ratings at these entities equal to Duke Energy's CCR. This resulted in the senior unsecured credit rating of Spectra Energy Capital being raised one ratings level to BBB and no changes to the senior unsecured ratings of Duke Energy Ohio, Duke Energy Indiana, and Duke Energy Kentucky as disclosed in the table below. At the same time, S&P assigned a senior unsecured credit rating to Duke Energy Carolinas equal to Duke Energy's CCR and left the credit ratings of the Spectra Energy Capital subsidiaries (Texas Eastern Transmission, LP, Westcoast, Union Gas and M&N Pipeline) and DETM unchanged. At the completion of S&P's April action, all the credit ratings were on stable outlook. S&P last affirmed its credit ratings for M&N Pipeline in July 2006 where they have remained unchanged with a stable outlook for the last several years.

In April 2006, upon Duke Energy's completion of the merger with Cinergy, Moody's upgraded the credit ratings of Duke Energy Carolinas (formerly rated as Duke Energy by Moody's prior to the merger), Spectra Energy Capital and Texas Eastern Transmission, LP one ratings level each and assigned an issuer rating to New Duke Energy. The credit ratings resulting from the April action are as disclosed in the table below, except for businesses transferred to Spectra Energy entities as discussed above. The credit ratings of Spectra Energy Capital and Texas Eastern Transmission, LP were Baa2 and Baa1 respectively following Moody's April action. Moody's concluded their April action placing New Duke Energy and Duke Energy Carolinas on positive outlook and Spectra Energy Capital and Texas Eastern Transmission, LP on stable outlook. Moody's also confirmed all of Cinergy and its subsidiaries credit ratings and changed the outlook to positive with the exception of Duke Energy Indiana, which was left on stable outlook. Moody's noted in their April action the substantial reduction in business and operating risk of Duke Energy Carolinas from the distribution of its ownership in Spectra Energy Capital to a new holding company (New Duke Energy) and the substantial reduction in business and operating risk of Spectra Energy Capital through the restructuring of its ownership in DEFS and the divestiture of the former DENA merchant generation assets and trading book. Moody's also noted the upgrade at Texas Eastern Transmission, LP in parallel to its parent Spectra Energy Capital.

In August 2005, Moody's concluded a review of M&N Pipeline and downgraded the credit ratings one ratings level to A2 concluding this action with a stable outlook. Moody's action was primarily as a result of their concerns over the downward revisions in the reserve estimates for the Sable Offshore Energy Project (SOEI) and reduced production by SOEI producers. In August 2006, Moody's revised the outlook for Maritimes & Northeast Pipeline, LLC to negative, noting the potential for a somewhat weaker shipper profile resulting from a recently announced expansion project on the U.S. portion of the pipeline.

The most recent rating action by DBRS occurred in June 2006 when DBRS confirmed the stable trend of Westcoast, Union Gas and M&N Pipeline following Duke Energy's announcement of the separation of the electric and gas businesses. Each of the credit ratings assigned by DBRS to these entities has remained unchanged for the last several years with a stable trend.

The following table summarizes the February 1, 2007 credit ratings from the agencies retained by Duke Energy, its principal funding subsidiaries and Duke Energy's trading and marketing subsidiary DETM.

Credit Ratings Summary as of February 1, 2007

	Standard and Poor's	Moody's Investor Service
Duke Energy[a]	BBB	Baa2
Duke Energy Carolinas, LLC[b]	BBB	A3
Cinergy[b]	BBB−	Baa2
Duke Energy Ohio, Inc.[b]	BBB	Baa1
Duke Energy Indiana, Inc.[b]	BBB	Baa1
Duke Energy Kentucky, Inc.[b]	BBB	Baa1
Duke Energy Trading and Marketing, LLC[c]	BBB−	Not applicable

(a) Represents corporate credit rating and issuer rating for S&P and Moody's respectively

(b) Represents senior unsecured credit rating

(c) Represents corporate credit rating

These entities credit ratings are dependent upon, among other factors, the ability to generate sufficient cash to fund capital and investment expenditures, while maintaining the strength of their current balance sheets. These credit ratings could be negatively impacted if as a result of market conditions or other factors, these entities are unable to maintain their current balance sheet strength, or if earnings and cash flow outlook materially deteriorates.

During the third quarter of 2005, the Board of Directors of Duke Energy authorized and directed management to execute the sale or disposition of substantially all of former DENA's remaining assets and contracts outside the Midwestern United States. On November 18, 2005, Duke Energy announced it signed an agreement to transfer substantially all of the former DENA portfolio of derivatives contracts to Barclays. Under the agreement, Barclays acquired substantially all of former DENA's outstanding gas and power derivatives contracts which essentially eliminated Duke Energy's credit, collateral, market and legal risk associated with former DENA's derivative trading positions effective on the date of signing. Substantially all of the underlying contracts have been transferred to Barclays.

Duke Energy operated a commercial marketing and trading business that was acquired as part of the merger with Cinergy in April 2006. In June 2006, Duke Energy announced it had reached an agreement to sell Cinergy's commercial marketing and trading business, as well as associated contracts. The sale closed in October 2006 and, upon closing, the buyer assumed the credit, collateral, market and legal risk associated with the trading positions acquired.

A reduction in the credit rating of Duke Energy to below investment grade as of December 31, 2006 would have resulted in Duke Energy posting additional collateral of up to approximately $377 million, including impacts of Cinergy and excluding any collateral requirements associated with the spin-off of the natural gas businesses in January 2007. The majority of this collateral is related to outstanding surety bonds.

Duke Energy would fund any additional collateral requirements through a combination of cash on hand and the use of credit facilities. Additionally, if credit ratings for Duke Energy or its affiliates fall below investment grade there is likely to be a negative impact on its working capital and terms of trade that is not possible to fully quantify, in addition to the posting of additional collateral and segregation of cash described above.

Clauses. Duke Energy may be required to repay certain debt should the credit ratings of Duke Energy Carolinas fall to a certain level at S&P or Moody's. As of December 31, 2006, Duke Energy had $13 million of senior unsecured notes which mature serially through 2012 that may be required to be repaid if Duke Energy Carolinas' senior unsecured debt ratings fall below BBB- at S&P or Baa3 at Moody's, and $23 million of senior unsecured notes which mature serially through 2016 that may be required to be repaid if Duke Energy Carolinas' senior unsecured debt ratings fall below BBB at S&P or Baa2 at Moody's.

Other Financing Matters. As of December 31, 2006, Duke Energy and its subsidiaries had effective SEC shelf registrations for up to $2,467 million in gross proceeds from debt and other securities, which include approximately $925 million of effective registrations at legacy Cinergy. Additionally, as of December 31, 2006, Duke Energy had 935 million Canadian dollars (approximately U.S. $807 million) available under Canadian shelf registrations for issuances in the Canadian market. Of the 935 million Canadian dollars available under Canadian shelf registrations, 500 million expires in May 2008 and 435 million expires in August 2008. Amounts available under U.S. and Canadian shelf registrations of approximately $592 million and 935 million Canadian dollars, respectively, relate to businesses included in the spin-off of the natural gas businesses on January 2, 2007 and, accordingly, are not available to Duke Energy subsequent to the consummation of the spin-off.

Duke Energy expects to continue its policy of paying regular cash dividends. There is no assurance as to the amount of future dividends because they depend on future earnings, capital requirements, and financial condition. Duke Energy has paid quarterly cash dividends for 81 consecutive years. Dividends on common and preferred stocks in 2007 are expected to be paid on March 15, June 18, September 17 and December 17, subject to the discretion of the Board of Directors.

Prior to June 2004, Duke Energy's Investor Direct Choice Plan allowed investors to reinvest dividends in common stock and to purchase common stock directly from Duke Energy. In June 2004, Duke Energy changed the method of dividend reinvestment to open market purchases. There were no issuances of common stock under the plan in either 2006 or 2005. Issuances of common stock under the plan were $36 million in 2004.

Duke Energy also sponsors an employee savings plan that covers substantially all U.S. employees. In April 2004, Duke Energy stopped issuing shares under the plan and the plan began making open market purchases with cash provided by Duke Energy. There were no issuances of common stock under the plan in 2006 or 2005. Issuances of common stock under the plan were $51 million in 2004. Duke Energy also issues shares of its common stock to meet other employee benefit requirements. Issuances of common stock to meet other employee benefit requirements were approximately $126 million in 2006, approximately $39 million for 2005 and approximately $12 million for 2004.

Off-Balance Sheet Arrangements

Duke Energy and certain of its subsidiaries enter into guarantee arrangements in the normal course of business to facilitate commercial transactions with third parties. These arrangements include financial and performance guarantees, stand-by letters of credit, debt guarantees, surety bonds and indemnifications. These arrangements are largely entered into by Duke Energy, Spectra Energy Capital and Cinergy. (See Note 18 to the Consolidated Financial Statements, "Guarantees and Indemnifications," for further details of the guarantee arrangements.)

Most of the guarantee arrangements entered into by Duke Energy enhance the credit standing of certain subsidiaries, non-consolidated entities or less than wholly owned entities, enabling them to conduct business. As such, these guarantee arrangements involve elements of performance and credit risk, which are not included on the Consolidated Balance Sheets. The possibility of Duke Energy, Spectra Energy Capital or Cinergy having to honor its contingencies is largely dependent upon the future operations of the subsidiaries, investees and other third parties, or the occurrence of certain future events.

Issuance of these guarantee arrangements is not required for the majority of Duke Energy's operations. Thus, if Duke Energy discontinued issuing these guarantee arrangements, there would not be a material impact to the consolidated results of operations, cash flows or financial position.

In contemplation of the spin-off of the natural gas businesses on January 2, 2007, certain guarantees that were previously issued by Spectra Energy Capital were transferred to Duke Energy prior to the consummation of the spin-off. This resulted in Duke Energy recording an immaterial liability for certain guarantees that were previously grandfathered under the provisions of FIN 45 and, therefore, were not recognized in the Consolidated Balance Sheets. Guarantees issued by Spectra Energy Capital or Natural Gas Transmission on or prior to December 31, 2006 remained with Spectra Energy Capital subsequent to the spin-off, except for certain guarantees that are in the process of being assigned to Duke Energy. During this assignment period, Duke Energy has indemnified Spectra Energy Capital against any losses incurred under these guarantee obligations.

Duke Energy Ohio, Duke Energy Indiana and Duke Energy Kentucky have an agreement to sell certain of their accounts receivable and related collections. Cinergy formed Cinergy Receivables to purchase, on a revolving basis, nearly all of the retail accounts receivable and related collections of Duke Energy Ohio, Duke Energy Indiana and Duke Energy Kentucky. Cinergy does not consolidate Cinergy Receivables since it meets the requirements to be accounted for as a qualifying special purpose entity (SPE). Duke Energy Ohio, Duke Energy Indiana and Duke Energy Kentucky each retain an interest in the receivables transferred to Cinergy Receivables. The transfers of receivables are accounted for as sales, pursuant to SFAS No. 140, "*Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities.*" For a more detailed discussion of our sales of accounts receivable, see Note 23 to the Consolidated Financial Statements, "Variable Interest Entities."

Cinergy holds interests in variable interest entities (VIEs), consolidated and unconsolidated, as defined by FASB Interpretation No. 46, "*Consolidation of Variable Interest Entities.*" For further information, see Note 1 to the Consolidated Financial Statements, "Summary of Significant Accounting Policies".

Duke Energy does not have any other material off-balance sheet financing entities or structures, except for normal operating lease arrangements and guarantee arrangements. (For additional information on these commitments, see Note 17 to the Consolidated Financial Statements, "Commitments and Contingencies" and Note 18 to the Consolidated Financial Statements, "Guarantees and Indemnifications.")

Contractual Obligations

Duke Energy enters into contracts that require payment of cash at certain specified periods, based on certain specified minimum quantities and prices. The following table summarizes Duke Energy's contractual cash obligations for each of the periods presented. The table below excludes all amounts classified as current liabilities on the Consolidated Balance Sheets, other than current maturities of long-term debt, as well as future obligations of businesses included in the spin-off of Spectra Energy on January 2, 2007. It is expected that the majority of current liabilities on the Consolidated Balance Sheets will be paid in cash in 2007.

Contractual Obligations as of December 31, 2006

		Payments Due By Period			
	Total	Less than 1 year (2007)	2–3 Years (2008 & 2009)	4–5 Years (2010 & 2011)	More than 5 Years (Beyond 2012)
			(in millions)		
Long-term debt[a]	$ 17,879	$ 1,695	$ 3,504	$ 1,749	$ 10,931
Capital leases[a]	113	15	36	25	37
Operating leases[b]	522	86	150	101	185
Purchase Obligations:[g]					
Firm capacity payments[c]	51	18	18	15	—
Energy commodity contracts[d]	5,189	1,872	1,901	918	498
Other purchase obligations[e]	2,065	912	778	39	336
Other long-term liabilities on the Consolidated Balance Sheets[f]	4,724	425	816	908	2,575
Total contractual cash obligations	$ 30,543	$ 5,023	$ 7,203	$ 3,755	$ 14,562

(a) See Note 15 to the Consolidated Financial Statements, "Debt and Credit Facilities". Amount includes interest payments over life of debt or capital lease.

(b) See Note 17 to the Consolidated Financial Statements, "Commitments and Contingencies".

(c) Includes firm capacity payments that provide Duke Energy with uninterrupted firm access to electricity transmission capacity, refining capacity and the option to convert natural gas to electricity at third-party owned facilities (tolling arrangements) in some power locations throughout North America. Also includes firm capacity payments under electric power agreements entered into to meet U.S. Franchised Electric and Gas' native load requirements.

(d) Includes contractual obligations to purchase physical quantities of electricity, coal and nuclear fuel. Amount includes certain normal purchases, energy derivatives and hedges per SFAS No. 133. For contracts where the price paid is based on an index, the amount is based on forward market prices at December 31, 2006. For certain of these amounts, Duke Energy may settle on a net cash basis since Duke Energy has entered into payment netting agreements with counterparties that permit Duke Energy to offset receivables and payables with such counterparties.

(e) Includes U.S. Franchised Electric and Gas' obligation to purchase an additional ownership interest in the Catawba Nuclear Station (see Note 5 to the Consolidated Financial Statements, "Joint Ownership of Generating and Transmission Facilities"), as well as contracts for software, telephone, data and consulting or advisory services. Amount also includes contractual obligations for engineering, procurement and construction costs for nuclear plant refurbishments, environmental projects on fossil facilities, pipeline and real estate projects, and major maintenance of certain merchant plants. Amount excludes certain open purchase orders for services that are provided on demand, and the timing of the purchase can not be determined.

(f) Includes expected retirement plan contributions for 2007 (see Note 22 to the Consolidated Financial Statements, "Employee Benefit Plans"), certain estimated executive benefits, and contributions to the NDTF (see Note 7 to the Consolidated Financial Statements, "Asset Retirement Obligations"). The amount of cash flows to be paid to settle the asset retirement obligations is not known with certainty as Duke Energy may use internal resources or external resources to perform retirement activities. As a result, cash obligations for asset retirement activities are excluded. Asset retirement obligations recognized on the Consolidated Balance Sheets total $2,301 million and the fair value of the NDTF, which will be used to help fund these obligations, is $1,775 million at December 31, 2006. Amount excludes reserves for litigation, environmental remediation, asbestos-related injuries and damages claims and self-insurance claims (see Note 17 to the Consolidated Financial Statements, "Commitments and Contingencies") because Duke Energy is uncertain as to the timing of when cash payments will be required. Additionally, amount excludes annual insurance premiums that are necessary to operate the business, including nuclear insurance (see Note 17 to the Consolidated Financial Statements, "Commitments and Contingencies"), funding of other post-employment benefits (see Note 22 to the Consolidated Financial Statements, "Employee Benefit Plans") and regulatory credits (see Note 4 to the Consolidated Financial Statements, "Regulatory Matters") because the amount and timing of the cash payments are uncertain. Also amount excludes Deferred Income Taxes and Investment Tax Credits on the Consolidated Balance Sheets since cash payments for income taxes are determined based primarily on taxable income for each discrete fiscal year. Liabilities Associated with Assets Held for Sale (see Note 13 to the Consolidated Financial Statements, "Discontinued Operations and Assets Held for Sale") are also excluded as Duke Energy expects these liabilities will be assumed by the buyer upon sale of the assets.

(g) Purchase obligations reflected in the Consolidated Balance Sheets have been excluded from the above table.

Quantitative and Qualitative Disclosures About Market Risk

Risk and Accounting Policies

Duke Energy is exposed to market risks associated with commodity prices, credit exposure, interest rates, equity prices and foreign currency exchange rates. Management has established comprehensive risk management policies to monitor and manage these market risks. Duke Energy's Chief Executive Officer and Chief Financial Officer are responsible for the overall approval of market risk management policies and the delegation of approval and authorization levels. The Finance and Risk Management Committee of the Board receives periodic updates from the Treasurer and other members of management, on market risk positions, corporate exposures, credit exposures and overall risk management activities. The Treasurer is responsible for the overall governance of managing credit risk and commodity price risk, including monitoring exposure limits.

See "Critical Accounting Policies—Risk Management Accounting and Revenue Recognition—Trading and Marketing Revenues" for further discussion of the accounting for derivative contracts.

Disclosures about market risks related to businesses transferred to Spectra Energy in January 2007 are not reflected herein since such exposures have no impact on the ongoing operations of Duke Energy post spin-off

Commodity Price Risk

Duke Energy is exposed to the impact of market fluctuations in the prices of electricity, coal, natural gas and other energy–related products marketed and purchased as a result of its ownership of energy related assets. Price risk represents the potential risk of loss from adverse changes in the market price of electricity or other energy commodities. Duke Energy employs established policies and procedures to manage its risks associated with these market fluctuations using various commodity derivatives, including swaps, futures, forwards and options. (See Note 1 to the Consolidated Financial Statements, "Summary of Significant Accounting Policies" and Note 8 to the Consolidated Financial Statements, "Risk Management and Hedging Activities, Credit Risk, and Financial Instruments.")

Validation of a contract's fair value is performed by an internal group independent of Duke Energy's deal origination areas. While Duke Energy uses common industry practices to develop its valuation techniques, changes in Duke Energy's pricing methodologies or the underlying assumptions could result in significantly different fair values and income recognition.

Hedging Strategies. Duke Energy closely monitors the risks associated with these commodity price changes on its future operations and, where appropriate, uses various commodity instruments such as electricity, coal and natural gas forward contracts to mitigate the effect of such fluctuations on operations. Duke Energy's primary use of energy commodity derivatives is to hedge the output and production of assets.

To the extent that instruments accounted for as hedges are effective in offsetting the transaction being hedged, there is no impact to the Consolidated Statements of Operations until delivery or settlement occurs. Accordingly, assumptions and valuation techniques for these contracts have no impact on reported earnings prior to settlement. Several factors influence the effectiveness of a hedge contract, including the use of contracts with different commodities or unmatched terms and counterparty credit risk. Hedge effectiveness is monitored regularly and measured each month. (See Note 1 to the Consolidated Financial Statements, "Summary of Significant Accounting Policies" and Note 8 to the Consolidated Financial Statements, "Risk Management and Hedging Activities, Credit Risk, and Financial Instruments.")

In addition to the hedge contracts described above and recorded on the Consolidated Balance Sheets, Duke Energy enters into other contracts that qualify for the normal purchases and sales exception described in paragraph 10 of SFAS No. 133, DIG Issue No. C15 and SFAS No. 149. For contracts qualifying for the scope exception, no recognition of the contract's fair value in the Consolidated Financial Statements is required until settlement of the contract unless the contract is designated as the hedged item in a fair value hedge. On a limited basis, U.S. Franchised Electric and Gas and Commercial Power apply the normal purchase and normal sales exception to certain contracts. Recognition for the contracts in the Consolidated Statements of Operations will be the same regardless of whether the contracts are accounted for as cash flow hedges or as normal purchases and sales, unless designated as the hedged item in a fair value hedge, assuming no hedge ineffectiveness.

Income recognition and realization related to normal purchases and normal sales contracts generally coincide with the physical delivery of power. However, Duke Energy's decisions in 2004 to sell former DENA Southeast Plants, reduce former DENA's interest in partially completed plants and sale or disposition of substantially all of former DENA's remaining physical and commercial assets outside of the Midwestern United States and certain contractual positions related to the Midwestern assets (see Normal Purchases and Normal Sales below) required the reassessment of all associated derivatives, including normal purchases and normal sales. This required a change from the application of the Accrual Model to the MTM Model for these contracts and resulted in recording substantial unrealized losses that had not previously been recognized in the Consolidated Financial Statements.

Generation Portfolio Risks. Duke Energy is primarily exposed to market price fluctuations of wholesale power and natural gas prices in the U.S. Franchised Electric and Gas and Commercial Power segments. Duke Energy optimizes the value of its bulk power marketing and non–regulated generation portfolios. The portfolios include generation assets (power and capacity), fuel, and emission allowances. Modeled forecasts of future generation output, fuel requirements, and emission allowance requirements are based on forward power, fuel and emission allowance markets. The component pieces of the portfolio are bought and sold based on this model in order to manage the economic value of the portfolio, where such market transparency exists. The generation portfolio not utilized to serve native load or committed load is subject to commodity price fluctuations. Based on a sensitivity analysis as of December 31, 2006 and 2005, it was estimated that a ten percent price change per mega–watt hour in wholesale power prices would have a corresponding effect on Duke Energy's pre–tax income of approximately $30 million in 2007 and $20 million in 2006, respectively. Based on a sensitivity analysis as of December 31, 2006, it was estimated that a ten percent price change per MMBtu in natural gas prices would have a corresponding effect on Duke Energy's pre–tax income of approximately $15 million in 2007.

Normal Purchases and Normal Sales. During the third quarter of 2005, Duke Energy's Board of Directors authorized and directed management to execute the sale or disposition of substantially all of former DENA's remaining assets and contracts outside the Midwestern United States, approximately 6,100 megawatts of power generation, and certain contractual positions related to the Midwestern assets (see Note 13 to the Consolidated Financial Statements, "Discontinued Operations and Assets Held for Sale"). As a result of this decision, Duke Energy recognized a pre-tax loss of approximately $1.9 billion in the third quarter of 2005 for the disqualification of its power and gas forward sales contracts previously designated under the normal purchases normal sales exception. This loss is partially offset by the recognition of a pre-tax gain of approximately $1.2 billion for the discontinuance of hedge accounting for natural gas and power cash flow hedges. Duke Energy has retained the Midwestern generation assets in the Commercial Power segment, representing approximately 3,600 megawatts of power generation (see Note 2 to the Consolidated Financial Statements, "Acquisitions and Dispositions" for further details on the completed Cinergy merger).

Trading and Undesignated Contracts. The risk in the trading portfolio is measured and monitored on a daily basis utilizing a Value-at-Risk (VaR) model to determine the potential one-day favorable or unfavorable VaR calculation. Duke Energy's VaR amounts for commodity derivatives recorded using the MTM Model are not material as a result of management decisions to dispose of certain businesses with higher risk profiles, including the former DENA operations outside the Midwestern United States and the Cinergy commercial marketing and trading businesses. In connection with the effort to reduce the risk profile, during 2006 Duke Energy finalized the sale of the former DENA power generation fleet outside of the Midwest to LS Power and sold the Cinergy commercial marketing and trading business to Fortis. Subsequent to the sales of both trading businesses, Duke Energy no longer uses VaR as a trading portfolio measure.

Other Commodity Risks. Duke Energy, through Commercial Power, owns coal-based synthetic fuel production facilities which convert coal feedstock into synthetic fuel for sale to third parties. The synthetic fuel produced at these facilities qualifies for tax credits (through 2007) in accordance with Internal Revenue Code Section 29/45K if certain requirements are satisfied. The Internal Revenue Code provides for a phase-out of synthetic fuel tax credits if the average annual wellhead oil prices increase above certain levels. If Commercial Power were to operate its synthetic fuel facilities based on December 31, 2006 prices throughout the entire forthcoming year, yet crude oil prices were to rise such that the tax credit is completely phased-out, projected net income in 2007 would be negatively impacted by approximately $100 million. Duke Energy is unlikely to experience a loss of this magnitude because the exposure to synthetic fuel tax credit phase-out is monitored and Duke Energy may choose to reduce or cease synthetic fuel production depending on the expectation of any potential tax credit phase-out. Duke Energy may also reduce its exposure to crude prices through the execution of derivative transactions. The objective of these activities is to reduce potential losses incurred if the reference price in a year exceeds a level triggering a phase-out of synthetic fuel tax credits.

Pre-tax income for 2007 or 2006 was also not expected to be materially impacted as of December 31, 2006 or 2005 for exposures to other commodities' price changes. These hypothetical calculations consider existing hedge positions and estimated production levels, but do not consider other potential effects that might result from such changes in commodity prices.

Duke Energy's exposure to commodity price risk is influenced by a number of factors, including contract size, length, market liquidity, location and unique or specific contract terms.

Credit Risk

Credit risk represents the loss that Duke Energy would incur if a counterparty fails to perform under its contractual obligations. To reduce credit exposure, Duke Energy seeks to enter into netting agreements with counterparties that permit Duke Energy to offset receivables and payables with such counterparties. Duke Energy attempts to further reduce credit risk with certain counterparties by entering into agreements that enable Duke Energy to obtain collateral or to terminate or reset the terms of transactions after specified time periods or upon the occurrence of credit-related events. Duke Energy may, at times, use credit derivatives or other structures and techniques to provide for third-party credit enhancement of Duke Energy's counterparties' obligations.

Duke Energy's principal customers for power and natural gas marketing and transportation services are industrial end-users, marketers, local distribution companies and utilities located throughout the U.S., Canada and Latin America. Duke Energy has concentrations of receivables from natural gas and electric utilities and their affiliates, as well as industrial customers and marketers throughout these regions. These concentrations of customers may affect Duke Energy's overall credit risk in that risk factors can negatively impact the credit quality of the entire sector. Where exposed to credit risk, Duke Energy analyzes the counterparties' financial condition prior to entering into an agreement, establishes credit limits and monitors the appropriateness of those limits on an ongoing basis.

The following table represents Duke Energy's distribution of unsecured credit exposures at December 31, 2006, including Spectra Energy businesses. These credit exposures are aggregated by ultimate parent company, include on and off balance sheet exposures, are presented net of collateral, and take into account contractual netting rights.

Distribution of Enterprise Credit Exposures

As of December 31, 2006

	% of Total
Investment Grade—Externally Rated	75%
Non-Investment Grade—Externally Rated	7
Investment Grade—Internally Rated	8
Non-Investment Grade—Internally Rated	10
Total	100%

"Externally Rated" represents enterprise relationships that have published ratings from at least one major credit rating agency. "Internally Rated" represents those relationships which have no rating by a major credit rating agency. For those relationships, Duke Energy utilizes appropriate risk rating methodologies and credit scoring models to develop an internal risk rating which is intended to map to an external rating equivalent. The total of the unsecured credit exposure included in the table above represents approximately 59% of the gross fair value of Duke Energy's Receivables and Unrealized Gains on Mark-to-Market and Hedging Transactions on the Consolidated Balance Sheets at December 31, 2006.

Duke Energy had no net exposure to any one customer that represented greater than 10% of the gross fair value of trade accounts receivable and unrealized gains on mark-to-market and hedging transactions at December 31, 2006. Excluding the businesses transferred to Spectra Energy in January 2007, the split between investment grade and non-investment grade would have been approximately 70% and 30%, respectively. Based on Duke Energy's policies for managing credit risk, its exposures and its credit and other reserves, Duke Energy does not anticipate a materially adverse effect on its consolidated financial position or results of operations as a result of non-performance by any counterparty.

During 2006, Duke Energy finalized the sale of the former DENA portfolio of derivative contracts to Barclays and sold the Cinergy commercial marketing and trading business to Fortis, which eliminated Duke Energy's credit, collateral, market and legal risk associated with these related trading positions.

In 1999, the Industrial Development Corp of the City of Edinburg, Texas (IDC) issued approximately $100 million in bonds to purchase equipment for lease to Duke Hidalgo (Hidalgo), a subsidiary of Spectra Energy Capital. Spectra Energy Capital unconditionally and irrevocably guaranteed the lease payments of Hidalgo to IDC through 2028. In 2000, Hidalgo was sold to Calpine Corporation and Spectra Energy Capital remained obligated under the lease guaranty. In January 2006, Hidalgo and its subsidiaries filed for bankruptcy protection in connection with the previous bankruptcy filing by its parent, Calpine Corporation in December 2005. Gross, undiscounted exposure under the guarantee obligation as of December 31, 2006 is approximately $200 million, including principal and interest payments. Duke Energy does not believe a loss under the guarantee obligation is probable as of December 31, 2006, but continues to evaluate the situation. Therefore, no reserves have been recorded for any contingent loss as of December 31, 2006. No demands for payment have been made under the guarantee. If losses are incurred under the guarantee, Spectra Energy Capital has certain rights which should allow it to mitigate such loss. Subsequent to the spin-off the natural gas businesses, this guarantee remained with Spectra Energy Capital. However, Duke Energy indemnified Spectra Energy Capital against any future losses that could arise from payments required under this guarantee.

Duke Energy's industry has historically operated under negotiated credit lines for physical delivery contracts. Duke Energy frequently uses master collateral agreements to mitigate certain credit exposures. The collateral agreements provide for a counterparty to post cash or letters of credit to the exposed party for exposure in excess of an established threshold. The threshold amount represents an unsecured credit limit, determined in accordance with the corporate credit policy. Collateral agreements also provide that the inability to post collateral is sufficient cause to terminate contracts and liquidate all positions.

Duke Energy also obtains cash or letters of credit from customers to provide credit support outside of collateral agreements, where appropriate, based on its financial analysis of the customer and the regulatory or contractual terms and conditions applicable to each transaction.

Collateral amounts held or posted may be fixed or may vary depending on the terms of the collateral agreement and the nature of the underlying exposure and cover normal purchases and normal sales, hedging contracts, and optimization contracts outstanding. Duke Energy may be required to return certain held collateral and post additional collateral should price movements adversely impact the value of open contracts or positions. In many cases, Duke Energy's and its counterparties' publicly disclosed credit ratings impact the amounts of additional collateral to be posted. If Duke Energy or its affiliates have a credit rating downgrade, it could result in reductions in Duke Energy's unsecured thresholds granted by counterparties. Likewise, downgrades in credit ratings of counterparties could require counterparties to post additional collateral to Duke Energy and its affiliates. (See "Liquidity and Capital Resources—Financing Cash Flows and Liquidity" for additional discussion of downgrades.)

Interest Rate Risk

Duke Energy is exposed to risk resulting from changes in interest rates as a result of its issuance of variable and fixed rate debt and commercial paper. Duke Energy manages its interest rate exposure by limiting its variable-rate exposures to percentages of total capitalization and by monitoring the effects of market changes in interest rates. Duke Energy also enters into financial derivative instruments, including, but not limited to, interest rate swaps, swaptions and U.S. Treasury lock agreements to manage and mitigate interest rate risk exposure. (See Notes 1, 8, and 15 to the Consolidated Financial Statements, "Summary of Significant Accounting Policies," "Risk Management and Hedging Activities, Credit Risk, and Financial Instruments," and "Debt and Credit Facilities.")

Based on a sensitivity analysis as of December 31, 2006, it was estimated that if market interest rates average 1% higher (lower) in 2007 than in 2006, interest expense, net of offsetting impacts in interest income, would increase (decrease) by approximately $3 million, excluding interest rate risk related to businesses transferred to Spectra Energy in January 2007. Comparatively, based on a sensitivity analysis as of December 31, 2005, had interest rates averaged 1% higher (lower) in 2006 than in 2005, it was estimated that interest expense, net of offsetting impacts in interest income, would have increased (decreased) by approximately $9 million. These amounts were estimated by considering the impact of the hypothetical interest rates on variable-rate securities outstanding, adjusted for interest rate hedges, short-term investments, cash and cash equivalents outstanding as of December 31, 2006 and 2005. The decrease in interest rate sensitivity was primarily due to the exclusion of interest rate risk, principally subsidiary debt and swaps, related to businesses transferred to Spectra Energy. If interest rates changed significantly, management would likely take actions to manage its exposure to the change. However, due to the uncertainty of the specific actions that would be taken and their possible effects, the sensitivity analysis assumes no changes in Duke Energy's financial structure.

Equity Price Risk

Duke Energy maintains trust funds, as required by the NRC and the NCUC, to fund the costs of nuclear decommissioning. (See Note 7 to the Consolidated Financial Statements, "Asset Retirement Obligations.") As of December 31, 2006 and 2005, these funds were invested primarily in domestic and international equity securities, fixed-rate, fixed-income securities and cash and cash equivalents. Per NRC and NCUC requirements, these funds may be used only for activities related to nuclear decommissioning. Those investments are exposed to price fluctuations in equity markets and changes in interest rates. Accounting for nuclear decommissioning recognizes that costs are recovered through U.S. Franchised Electric and Gas' rates, and fluctuations in equity prices or interest rates do not affect Duke Energy's consolidated results of operations. Earnings or losses of the fund will ultimately impact the amount of costs recovered from U.S. Franchised Electric and Gas' rates.

Bison, Duke Energy's wholly owned captive insurance subsidiary, maintains investments to fund various business risks and losses, such as workers compensation, property, business interruption and general liability. Those investments are exposed to price fluctuations in equity markets and changes in interest rates.

Duke Energy's costs of providing non-contributory defined benefit retirement and postretirement benefit plans are dependent upon a number of factors, such as the rates of return on plan assets, discount rate, the rate of increase in health care costs and contributions made to the plans.

Foreign Currency Risk

Duke Energy is exposed to foreign currency risk from investments in international affiliate businesses owned and operated in foreign countries and from certain commodity-related transactions within domestic operations. To mitigate risks associated with foreign currency fluctuations, contracts may be denominated in or indexed to the U.S. Dollar and/or local inflation rates, or investments may be naturally hedged through debt denominated or issued in the foreign currency. Duke Energy may also use foreign currency derivatives, where possible, to manage its risk related to foreign currency fluctuations. To monitor its currency exchange rate risks, Duke Energy uses sensitivity analysis, which measures the impact of devaluation of the foreign currencies to which it has exposure.

In 2007, Duke Energy's primary foreign currency rate exposures are expected to be the Brazilian Real and the Peruvian New Sol. A 10% devaluation in the currency exchange rates as of December 31, 2006 in all of Duke Energy's exposure currencies would result in an estimated net pre-tax loss on the translation of local currency earnings of approximately $7 million to Duke Energy's Consolidated Statements of Operations in 2007. The Consolidated Balance Sheet would be negatively impacted by approximately $120 million currency translation through the cumulative translation adjustment in AOCI as of December 31, 2006 as a result of a 10% devaluation in the currency exchange rates.

OTHER ISSUES

Spin-off of the Natural Gas Businesses. In June 2006, the Board of Directors of Duke Energy authorized management to pursue a plan to create two separate publicly traded companies by spinning off Duke Energy's natural gas businesses to Duke Energy shareholders. The spin-off was effective January 2, 2007. The new natural gas company, which is named Spectra Energy, principally consists of Duke Energy's Natural Gas Transmission business segment, which includes Union Gas, and also includes Duke Energy's 50% ownership interest in DEFS. Approximately $20 billion of assets, $13 billion of liabilities (which includes approximately $8.6 billion of debt issued by Spectra Energy Capital and its consolidated subsidiaries) and $7 billion of common stockholders' equity were distributed from Duke Energy as of the date of the spin-off. Assets and liabilities of entities included in the spin-off of Spectra Energy were transferred from Duke Energy on a historical cost basis on the date of the spin-off transaction. As a result of the spin-off transaction, on January 2, 2007, in lieu of adjusting the conversion ratio of the convertible debt, Duke Energy issued approximately 2.4 million shares of Spectra Energy common stock to holders of Duke Energy's convertible senior notes due 2023, consistent with the terms of the debt agreements. The issuance of Spectra Energy shares to the convertible debt holders is expected to result in a pretax charge in the range of $20 million to $30 million in Duke Energy's 2007 consolidated statement of operations. The historical results of the natural gas businesses are expected to be treated as discontinued operations at Duke Energy in future periods beginning with the first quarter of 2007. The primary businesses remaining in Duke Energy post-spin are the U.S. Franchised Electric and Gas business segment, the Commercial Power business segment, the International Energy business segment and Duke Energy's effective 50% interest in the Crescent JV. The decision to spin off the natural gas business is expected to deliver long-term value to shareholders.

Energy Policy Act of 2005. The Energy Policy Act of 2005 was signed into law in August 2005. The legislation directs specified agencies to conduct a significant number of studies on various aspects of the energy industry and to implement other provisions through rulemakings. Among the key provisions, the Energy Policy Act of 2005 repeals the PUHCA of 1935, directs FERC to establish a self-regulating electric reliability organization governed by an independent board with FERC oversight, extends the Price Anderson Act for 20 years (until 2025), provides loan guarantees, standby support and production tax credits for new nuclear reactors, gives FERC enhanced merger approval authority, provides FERC new backstop authority for the siting of certain electric transmission projects, streamlines the processes for approval and permitting of interstate pipelines, and reforms hydropower relicensing. FERC's enhanced merger authority will not apply to transactions pending with the FERC as of August 8, 2005, such as the Duke Energy and Cinergy merger, as discussed in Note 2 to the Consolidated Financial Statements, "Acquisitions and Dispositions." In late 2005 and early 2006, FERC initiated several rulemakings as directed by the Energy Policy Act of 2005. Duke Energy is currently evaluating these proposals and does not anticipate that these rulemakings will have a material adverse effect on its consolidated results of operations, cash flows or financial position.

Global Climate Change. The greenhouse gas policy of the United States currently favors voluntary actions to reduce emissions and continued research and technology development over near-term mandatory greenhouse gas emission reduction requirements. Although several bills have been introduced in Congress that would mandate greenhouse gas emission reductions, none have advanced through the legislature and presently there are no federal mandatory greenhouse gas reduction requirements. While it is possible that Congress will adopt some form of mandatory greenhouse gas emission reduction legislation in the future, the timing and specific requirements of any such legislation are highly uncertain. Several Northeastern states and California are in the process of developing their own mandatory greenhouse gas emission reduction programs; none of which will impact Duke Energy's operations.

Duke Energy supports the enactment of U.S. federal legislation that would require a gradual transition to a lower carbon-intensive economy. Legislation preferably would be in the form of a federal-level carbon tax or cap-and-trade based program. Duke Energy, believing that it is in the best interest of its investors and customers to do so, is actively participating in the evolution of federal policy on this important issue.

Duke Energy's proactive role in climate change policy debates in the United States does not change the uncertainty around such policy. Due to the speculative outlook regarding U.S. federal policy, Duke Energy cannot estimate the potential effect of future U.S. greenhouse gas policy on its future consolidated results of operations, cash flows or financial position. Duke Energy will assess and respond to the potential implications of U.S. greenhouse gas policy for its business operations if policy becomes sufficiently developed and certain to support a meaningful assessment.

This disclosure related to the global climate change excludes developments in Canada due to the spin-off of Duke Energy's natural gas businesses on January 2, 2007.

(For additional information on other issues related to Duke Energy, see Note 4 to the Consolidated Financial Statements, "Regulatory Matters" and Note 17 to the Consolidated Financial Statements, "Commitments and Contingencies.")

New Accounting Standards

The following new accounting standards have been issued, but have not yet been adopted by Duke Energy as of December 31, 2006:

SFAS No. 155, "Accounting for Certain Hybrid Financial Instruments—an amendment of FASB Statements No. 133 and 140" (SFAS No. 155). In February 2006, the FASB issued SFAS No. 155, which amends *SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities"* and *SFAS No. 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities" (SFAS No. 140).* SFAS No. 155 allows financial instruments that have embedded derivatives to be accounted for at fair value at acquisition, at issuance, or when a previously recognized financial instrument is subject to a remeasurement (new basis) event, on an instrument-by-instrument basis, in cases in which a derivative would otherwise have to be bifurcated. SFAS No. 155 is effective for Duke Energy for all financial instruments acquired, issued, or subject to remeasurement after January 1, 2007, and for certain hybrid financial instruments that have been bifurcated prior to the effective date, for which the effect is to be reported as a cumulative-effect adjustment to beginning retained earnings. Duke Energy does not anticipate the adoption of SFAS No. 155 will have any material impact on its consolidated results of operations, cash flows or financial position.

SFAS No. 156, "Accounting for Servicing of Financial Assets—an amendment of FASB Statement No. 140" (SFAS No. 156). In March 2006, the FASB issued SFAS No. 156, which amends SFAS No. 140. SFAS No. 156 requires recognition of a servicing asset or liability when an entity enters into arrangements to service financial instruments in certain situations. Such servicing assets or servicing liabilities are required to be initially measured at fair value, if practicable. SFAS No. 156 also allows an entity to subsequently measure its servicing assets or servicing liabilities using either an amortization method or a fair value method. SFAS No. 156 is effective for Duke Energy as of January 1, 2007, and must be applied prospectively, except that where an entity elects to remeasure separately recognized existing arrangements and reclassify certain available-for-sale securities to trading securities, any effects must be reported as a cumulative-effect adjustment to retained earnings. Duke Energy does not anticipate the adoption of SFAS No. 156 will have any material impact on its consolidated results of operations, cash flows or financial position.

SFAS No. 157, "Fair Value Measurements" (SFAS No. 157). In September 2006, the FASB issued SFAS No. 157, which defines fair value, establishes a framework for measuring fair value in GAAP, and expands disclosures about fair value measurements. SFAS No. 157 does not require any new fair value measurements. However, in some cases, the application of SFAS No. 157 may change Duke Energy's current practice for measuring and disclosing fair values under other accounting pronouncements that require or permit fair value measurements. For Duke Energy, SFAS No. 157 is effective as of January 1, 2008 and must be applied prospectively except in certain cases. Duke Energy is currently evaluating the impact of adopting SFAS No. 157, and cannot currently estimate the impact of SFAS No. 157 on its consolidated results of operations, cash flows or financial position.

SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities" (SFAS No. 159). In February 2007, the FASB issued SFAS No. 159, which permits entities to choose to measure many financial instruments and certain other items at fair value. For Duke Energy, SFAS No. 159 is effective as of January 1, 2008 and will have no impact on amounts presented for periods prior to the effective date. Duke Energy cannot currently estimate the impact of SFAS No. 159 on its consolidated results of operations, cash flows or financial position and has not yet determined whether or not it will choose to measure items subject to SFAS No. 159 at fair value.

FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes—an interpretation of FASB Statement No. 109" (FIN 48). In July 2006, the FASB issued FIN 48, which provides guidance on accounting for income tax positions about which Duke Energy has concluded there is a level of uncertainty with respect to the recognition in Duke Energy's financial statements. FIN 48 prescribes a minimum recognition threshold a tax position is required to meet. Tax positions are defined very broadly and include not only tax deductions and credits but also decisions not to file in a particular jurisdiction, as well as the taxability of transactions. Duke Energy will implement FIN 48 effective January 1, 2007. The implementation is expected to result in a cumulative effect adjustment to beginning Retained Earnings on the Consolidated Statement of Common Stockholders' Equity and Comprehensive Income (Loss) in the first quarter 2007 in the range of $15 million to $30 million. Corresponding entries will impact a variety of balance sheet line items, including Deferred Income Taxes, Taxes Accrued, Other Liabilities, and Goodwill. Upon implementation of FIN 48, Duke Energy will reflect interest expense related to taxes as Interest Expense, in the Consolidated Statement of Operations. In addition, subsequent accounting for FIN 48 (after January 1, 2007) will involve an evaluation to determine if any changes have occurred that would impact the existing uncertain tax positions as well as determining whether any new tax positions are uncertain. Any impacts resulting from the evaluation of existing uncertain tax positions or from the recognition of new uncertain tax positions would impact income tax expense and interest expense in the Consolidated Statement of Operations, with offsetting impacts to the balance sheet line items described above. Because of the spin-off of Spectra Energy in the first quarter of 2007, certain liabilities and deferred tax assets related to uncertain tax positions filed on Spectra Energy tax returns will be removed from Duke Energy's balance sheet. Uncertain tax positions on consolidated or combined tax returns filed by Duke Energy which are indemnified by Spectra Energy will be recorded as receivables from Spectra Energy.

FASB Staff Position (FSP) No. FAS 123(R)-5, "Amendment of FASB Staff Position FAS 123(R)-1" (FSP No. FAS 123(R)-5). In October 2006, the FASB staff issued FSP No. FAS 123(R)-5 to address whether a modification of an instrument in connection with an equity restructuring should be considered a modification for purposes of applying *FSP No. FAS 123(R)-1, "Classification and Measurement of Freestanding Financial Instruments Originally Issued in Exchange for Employee Services under FASB Statement No. 123(R) (FSP No. FAS 123(R)-1)."* In August 2005, the FASB staff issued FSP FAS 123(R)-1 to defer indefinitely the effective date of paragraphs A230—A232 of SFAS No. 123(R), and thereby require entities to apply the recognition and measurement provisions of SFAS No. 123(R) throughout the life of an instrument, unless the instrument is modified when the holder is no longer an employee. The recognition and measurement of an instrument that is modified when the holder is no longer an employee should be determined by other applicable generally accepted accounting principles. FSP No. FAS 123(R)-5 addresses modifications of stock-based awards made in connection with an equity restructuring and clarifies that for instruments that were originally issued as employee compensation and then modified, and that modification is made to the terms of the instrument solely to reflect an equity restructuring that occurs when the holders are no longer employees, no change in the recognition or the measurement (due to a change in classification) of those instruments will result if certain conditions are met. This FSP is effective for Duke Energy as of January 1, 2007. The impact to Duke Energy of applying FSP No. FAS 123(R)-5 in subsequent periods will be dependent upon the nature of any modifications to Duke Energy's share-based compensation awards.

FSP No. AUG AIR-1, "Accounting for Planned Major Maintenance Activities," (FSP AUG AIR-1). In September 2006, the FASB Staff issued FSP No. AUG AIR-1. This FSP prohibits the use of the accrue-in-advance method of accounting for planned major maintenance activities in annual and interim financial reporting periods, if no liability is required to be recorded for an asset retirement obligation based on a legal obligation for which the event obligating the entity has occurred. The FSP also requires disclosures regarding the method of accounting for planned major maintenance activities and the effects of implementing the FSP. The guidance in this FSP is effective for Duke Energy as of January 1, 2007 and will be applied and retrospectively for all financial statements presented. Duke Energy does not anticipate the adoption of FSP No. AUG AIR-1 will have any material impact on its consolidated results of operations, cash flows or financial position.

EITF Issue No. 06-3, "How Taxes Collected from Customers and Remitted to Governmental Authorities Should Be Presented in the Income Statement (That Is, Gross versus Net Presentation)" (EITF No. 06-3). In June 2006, the EITF reached a consensus on EITF No. 06-3 to address any tax assessed by a governmental authority that is directly imposed on a revenue-producing transaction between a seller and a customer and may include, but are not limited to, sales, use, value added, and some excise taxes. For taxes within the issue's scope, the consensus requires that entities present such taxes on either a gross (i.e. included in revenues and costs) or net (i.e. exclude from revenues) basis according to their accounting policies, which should be disclosed. If such taxes are reported gross and are significant, entities should disclose the amounts of those taxes. Disclosures may be made on an aggregate basis. The consensus is effective for Duke Energy beginning January 1, 2007. Duke Energy does not anticipate the adoption of EITF No. 06-3 will have any material impact on its consolidated results of operations, cash flows or financial position.

EITF Issue No. 06-5, "Accounting for Purchases of Life Insurance—Determining the Amount That Could Be Realized in Accordance with FASB Technical Bulletin No. 85-4" (EITF No. 06-5). In June 2006, the EITF reached a consensus on the accounting for corporate-owned and bank-owned life insurance policies. EITF No. 06-5 requires that a policyholder consider the cash surrender value and any additional amounts to be received under the contractual terms of the policy in determining the amount that could be realized under the insurance contract. Amounts that are recoverable by the policyholder at the discretion of the insurance company must be excluded from the amount that could be realized. Fixed amounts that are recoverable by the policyholder in future periods in excess of one year from the surrender of the policy must be recognized at their present value. EITF No. 06-5 is effective for Duke Energy as of January 1, 2007 and must be applied as a change in accounting principle through a cumulative-effect adjustment to retained earnings or other components of equity as of January 1, 2007. Duke Energy does not anticipate the adoption of EITF No. 06-5 will have any material impact on its consolidated results of operations, cash flows or financial position.

EITF Issue No. 06-6, "Debtor's Accounting for a Modification (or Exchange) of Convertible Debt Instruments" (EITF No. 06-6). In November 2006, the EITF reached a consensus on EITF No. 06-6. EITF No. 06-6 addresses how a modification of a debt instrument (or an exchange of debt instruments) that affects the terms of an embedded conversion option should be considered in the issuer's analysis of whether debt extinguishment accounting should be applied, and further addresses the accounting for a modification of a debt instrument (or an exchange of debt instruments) that affects the terms of an embedded conversion option when extinguishment accounting is not applied. EITF No. 06-6 applies to modifications (or exchanges) occurring in interim or annual reporting periods beginning after November 29, 2006, regardless of when the instrument was originally issued. Early application is permitted for modifications (or exchanges) occurring in periods for which financial statements have not been issued. There were no modifications to, or exchanges of, any of Duke Energy's debt instruments within the scope of EITF No. 06-6 in 2006. EITF No. 06-6 is effective for Duke Energy beginning January 1, 2007. The impact to Duke Energy of applying EITF No. 06-6 in subsequent periods will be dependent upon the nature of any modifications to, or exchanges of, any debt instruments within the scope of EITF No. 06-6. Refer to Note 15, "Debt and Credit Facilities."

Item 7A. Quantitative and Qualitative Disclosures About Market Risk.

See "Management's Discussion and Analysis of Results of Operations and Financial Condition, Quantitative and Qualitative Disclosures About Market Risk."

Item 8. Financial Statements and Supplementary Data.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of Duke Energy Corporation:

We have audited the accompanying consolidated balance sheets of Duke Energy Corporation and subsidiaries (the "Company") as of December 31, 2006 and 2005, and the related consolidated statements of operations, stockholders' equity and comprehensive income, and cash flows for each of the three years in the period ended December 31, 2006. Our audits also included the consolidated financial statement schedule listed in the Index at Item 15. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Duke Energy Corporation and subsidiaries as of December 31, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

As discussed in Note 1 to the consolidated financial statements, in 2006 the Company changed its method of accounting for defined benefit pension and other postretirement plans as a result of adopting Statement of Financial Accounting Standard No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans*.

As discussed in Notes 1 and 25 to the consolidated financial statements, the Company's spin-off of the natural gas businesses was completed on January 2, 2007.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Company's internal control over financial reporting as of December 31, 2006, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 1, 2007 expressed an unqualified opinion on management's assessment of the effectiveness of the Company's internal control over financial reporting and an unqualified opinion on the effectiveness of the Company's internal control over financial reporting

/s/ DELOITTE & TOUCHE LLP

Charlotte, North Carolina

March 1, 2007

DUKE ENERGY CORPORATION

Consolidated Statements of Operations

(In millions, except per-share amounts)

	Years Ended December 31,		
	2006	2005	2004
Operating Revenues			
Non-regulated electric, natural gas, natural gas liquids, and other	$ 3,158	$ 7,212	$11,322
Regulated electric	7,678	5,406	5,041
Regulated natural gas and natural gas liquids	4,348	3,679	3,233
Total operating revenues	15,184	16,297	19,596
Operating Expenses			
Natural gas and petroleum products purchased	1,829	5,827	9,225
Operation, maintenance and other	4,415	3,540	3,313
Fuel used in electric generation and purchased power	3,403	1,610	1,576
Depreciation and amortization	2,049	1,728	1,750
Property and other taxes	769	571	513
Impairments and other charges	28	140	64
Total operating expenses	12,493	13,416	16,441
Gains on Sales of Investments in Commercial and Multi-Family Real Estate	201	191	192
Gains (Losses) on Sales of Other Assets and Other, net	276	534	(416)
Operating Income	3,168	3,606	2,931
Other Income and Expenses			
Equity in earnings of unconsolidated affiliates	732	479	161
(Losses) Gains on sales and impairments of equity investments	(20)	1,225	(4)
Gain on sale of subsidiary stock	15	—	—
Other income and expenses, net	281	105	147
Total other income and expenses	1,008	1,809	304
Interest Expense	1,253	1,066	1,282
Minority Interest Expense	61	538	200
Earnings From Continuing Operations Before Income Taxes	2,862	3,811	1,753
Income Tax Expense from Continuing Operations	843	1,282	507
Income From Continuing Operations	2,019	2,529	1,246
(Loss) Income From Discontinued Operations, net of tax	(156)	(701)	244
Income Before Cumulative Effect of Change in Accounting Principle	1,863	1,828	1,490
Cumulative Effect of Change in Accounting Principle, net of tax and minority interest	—	(4)	—
Net Income	1,863	1,824	1,490
Dividends and Premiums on Redemption of Preferred and Preference Stock	—	12	9
Earnings Available For Common Stockholders	$ 1,863	$ 1,812	$ 1,481
Common Stock Data			
Weighted-average shares outstanding			
Basic	1,170	934	931
Diluted	1,188	970	966
Earnings per share (from continuing operations)			
Basic	$ 1.73	$ 2.69	$ 1.33
Diluted	$ 1.70	$ 2.60	$ 1.29
(Loss) earnings per share (from discontinued operations)			
Basic	$ (0.14)	$ (0.75)	$ 0.26
Diluted	$ (0.13)	$ (0.72)	$ 0.25
Earnings per share (before cumulative effect of change in accounting principle)			
Basic	$ 1.59	$ 1.94	$ 1.59
Diluted	$ 1.57	$ 1.88	$ 1.54
Earnings per share			
Basic	$ 1.59	$ 1.94	$ 1.59
Diluted	$ 1.57	$ 1.88	$ 1.54
Dividends per share	$ 1.26	$ 1.17	$ 1.10

See Notes to Consolidated Financial Statements

DUKE ENERGY CORPORATION

Consolidated Balance Sheets

(In millions)

	December 31,	
	2006	2005
ASSETS		
Current Assets		
Cash and cash equivalents	$ 948	$ 511
Short-term investments	1,514	632
Receivables (net of allowance for doubtful accounts of $94 at December 31, 2006 and $127 at December 31, 2005)	2,256	2,580
Inventory	1,358	863
Assets held for sale	28	1,528
Unrealized gains on mark-to-market and hedging transactions	107	87
Other	729	1,756
Total current assets	6,940	7,957
Investments and Other Assets		
Investments in unconsolidated affiliates	2,305	1,933
Nuclear decommissioning trust funds	1,775	1,504
Goodwill	8,175	3,775
Intangibles, net	905	65
Notes receivable	224	138
Unrealized gains on mark-to-market and hedging transactions	248	62
Assets held for sale	134	3,597
Investments in residential, commercial and multi-family real estate (net of accumulated depreciation of $17 at December 31, 2005)	—	1,281
Other	2,304	2,678
Total investments and other assets	16,070	15,033
Property, Plant and Equipment		
Cost	58,330	40,823
Less accumulated depreciation and amortization	16,883	11,623
Net property, plant and equipment	41,447	29,200
Regulatory Assets and Deferred Debits		
Deferred debt expense	320	269
Regulatory assets related to income taxes	1,361	1,338
Other	2,562	926
Total regulatory assets and deferred debits	4,243	2,533
Total Assets	$ 68,700	$54,723

See Notes to *Consolidated Financial Statements*

DUKE ENERGY CORPORATION

Consolidated Balance Sheets—(Continued)

(In millions, except per-share amounts)

	December 31,	
	2006	2005
LIABILITIES AND COMMON STOCKHOLDERS' EQUITY		
Current Liabilities		
Accounts payable	$ 1,686	$ 2,431
Notes payable and commercial paper	450	83
Taxes accrued	434	327
Interest accrued	302	230
Liabilities associated with assets held for sale	26	1,488
Current maturities of long-term debt	1,605	1,400
Unrealized losses on mark-to-market and hedging transactions	134	204
Other	1,976	2,255
Total current liabilities	6,613	8,418
Long-term Debt	18,118	14,547
Deferred Credits and Other Liabilities		
Deferred income taxes	7,003	5,253
Investment tax credit	175	144
Unrealized losses on mark-to-market and hedging transactions	238	10
Liabilities associated with assets held for sale	18	2,085
Asset retirement obligations	2,301	2,058
Other	7,327	5,020
Total deferred credits and other liabilities	17,062	14,570
Commitments and Contingencies		
Minority Interests	805	749
Common Stockholders' Equity		
Common stock, $0.001 par value, 2 billion shares authorized; 1,257 million and zero shares outstanding at December 31, 2006 and December 31, 2005, respectively	1	—
Common stock, no par, 2 billion shares authorized; zero and 928 million shares outstanding at December 31, 2006 and December 31, 2005, *respectively*	—	10,446
Additional paid-in capital	19,854	—
Retained earnings	5,652	5,277
Accumulated other comprehensive income	595	716
Total common stockholders' equity	26,102	16,439
Total Liabilities and Common Stockholders' Equity	$ 68,700	$54,723

See Notes to Consolidated Financial Statements

DUKE ENERGY CORPORATION

Consolidated Statements of Cash Flows

(In millions)

	Years Ended December 31,		
	2006	2005	2004
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$ 1,863	$ 1,824	$ 1,490
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization (including amortization of nuclear fuel)	2,215	1,884	2,037
Cumulative effect of change in accounting principle	—	4	—
Gains on sales of investments in commercial and multi-family real estate	(201)	(191)	(201)
Gains on sales of equity investments and other assets	(365)	(1,771)	(193)
Impairment charges	48	159	194
Deferred income taxes	250	282	867
Minority Interest	61	538	195
Equity in earnings of unconsolidated affiliates	(732)	(479)	(161)
Purchased capacity levelization	(14)	(14)	92
Contributions to company-sponsored pension plans	(172)	(45)	(279)
(Increase) decrease in			
Net realized and unrealized mark-to-market and hedging transactions	(134)	443	216
Receivables	844	(249)	(231)
Inventory	(24)	(80)	(48)
Other current assets	1,276	(944)	(33)
Increase (decrease) in			
Accounts payable	(1,524)	117	(5)
Taxes accrued	(69)	53	188
Other current liabilities	(594)	622	91
Capital expenditures for residential real estate	(322)	(355)	(322)
Cost of residential real estate sold	143	294	268
Other, assets	1,005	193	(155)
Other, liabilities	194	533	158
Net cash provided by operating activities	3,748	2,818	4,168
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures	(3,381)	(2,327)	(2,161)
Investment expenditures	(89)	(43)	(46)
Acquisitions, net of cash acquired	(284)	(294)	—
Cash acquired from acquisition of Cinergy	147	—	—
Purchases of available-for-sale securities	(33,436)	(40,317)	(65,929)
Proceeds from sales and maturities of available-for-sale securities	32,596	40,131	65,098
Net proceeds from the sales of equity investments and other assets, and sales of and collections on notes receivable	2,861	2,375	1,619
Proceeds from the sales of commercial and multi-family real estate	254	372	606
Settlement of net investment hedges and other investing derivatives	(163)	(296)	—
Distributions from equity investments	152	383	—
Purchases of emission allowances	(228)	(18)	—
Sales of emission allowances	194	—	—
Other	49	(92)	20
Net cash used in investing activities	(1,328)	(126)	(793)
CASH FLOWS FROM FINANCING ACTIVITIES			
Proceeds from the:			
Issuance of long-term debt	2,369	543	153
Issuance of common stock and common stock related to employee benefit plans	127	41	1,704
Payments for the redemption of:			
Long-term debt	(2,098)	(1,346)	(3,646)
Preferred stock of a subsidiary	(12)	(134)	(176)
Decrease in cash overdrafts	(2)	—	—
Notes payable and commercial paper	(412)	165	(67)
Distributions to minority interests	(304)	(861)	(1,477)
Contributions from minority interests	247	779	1,277
Dividends paid	(1,488)	(1,105)	(1,065)
Repurchase of common shares	(500)	(933)	—
Proceeds from Duke Energy Income Fund	104	110	—
Other	8	24	19
Net cash used in financing activities	(1,961)	(2,717)	(3,278)
Changes in cash and cash equivalents included in assets held for sale	(22)	3	39
Net increase (decrease) in cash and cash equivalents	437	(22)	136
Cash and cash equivalents at beginning of period	511	533	397
Cash and cash equivalents at end of period	$ 948	$ 511	$ 533
Supplemental Disclosures			
Cash paid for interest, net of amount capitalized	$ 1,154	$ 1,089	$ 1,323
Cash paid (refunded) for income taxes	$ 460	$ 546	$ (339)
Acquisition of Cinergy Corp.			
Fair value of assets acquired	$ 17,304	$ —	$ —
Liabilities assumed	$ 12,709	$ —	$ —
Issuance of common stock	$ 8,993	$ —	$ —
Significant non-cash transactions:			
Conversion of convertible notes to stock	$ 632	$ 28	$ —
AFUDC—equity component	$ 58	$ 30	$ 25
Transfer of DEFS Canadian Facilities	$ —	$ 97	$ —
Debt retired in connection with disposition of business	$ —	$ —	$ 840

Note receivable from sale of southeastern plants	$ —	$ —	$ 48
Remarketing of senior notes	$ —	$ —	$ 1,625

See Notes to Consolidated Financial Statements

Table of Contents
PART II

DUKE ENERGY CORPORATION

Consolidated Statements of Common Stockholders' Equity

and Comprehensive Income

(In millions)

	Common Stock Shares	Common Stock	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss): Foreign Currency Adjustments	Net Gains (Losses) on Cash Flow Hedges	Minimum Pension Liability Adjustment	SFAS No. 158 Adjustment	Other	Total
Balance December 31, 2003	911	$ 9,513		$ 4,066	$315	$ 298	$ (444)	$ —	$ —	$ 13,748
Net income	—	—	—	1,490	—	—	—	—	—	1,490
Other Comprehensive Income										
Foreign currency translation adjustments	—	—	—	—	279	—	—	—	—	279
Foreign currency translation adjustments reclassified into earnings as a result of the sale of Asia-Pacific Business	—	—	—	—	(54)	—	—	—	—	(54)
Net unrealized gains on cash flow hedges (b)	—	—	—	—	—	311	—	—	—	311
Reclassification into earnings from cash flow hedges (c)	—	—	—	—	—	(83)	—	—	—	(83)
Minimum pension liability adjustment (d)	—	—	—	—	—	—	28	—	—	28
Total comprehensive income										1,971
Dividend reinvestment and employee benefits	5	128	—	—	—	—	—	—	—	128
Equity offering	41	1,625	—	—	—	—	—	—	—	1,625
Common stock dividends	—	—	—	(1,018)	—	—	—	—	—	(1,018)
Preferred and preference stock dividends	—	—	—	(9)	—	—	—	—	—	(9)
Other capital stock transactions, net	—	—	—	(4)	—	—	—	—	—	(4)
Balance December 31, 2004	957	$ 11,266	$ —	$ 4,525	$540	$ 526	$ (416)	$ —	$ —	$ 16,441
Net income	—	—	—	1,824	—	—	—	—	—	1,824
Other Comprehensive Income										
Foreign currency translation adjustments (a)	—	—	—	—	306	—	—	—	—	306
Net unrealized gains on cash flow hedges (b)	—	—	—	—	—	413	—	—	—	413
Reclassification into earnings from cash flow hedges (c)	—	—	—	—	—	(1,026)	—	—	—	(1,026)
Minimum pension liability adjustment (d)	—	—	—	—	—	—	356	—	—	356
Other (f)								—	17	17
Total comprehensive income										1,890
Dividend reinvestment and employee benefits	3	85		—	—	—	—	—	—	85
Stock repurchase	(33)	(933)		—	—	—	—	—	—	(933)
Conversion of debt	1	28								28
Common stock dividends	—	—	—	(1,093)	—	—	—	—	—	(1,093)
Preferred and preference stock dividends	—	—	—	(12)	—	—	—	—	—	(12)
Other capital stock transactions, net	—	—	—	33	—	—	—	—	—	33
Balance December 31, 2005	928	$ 10,446	$ —	$ 5,277	$846	$ (87)	$ (60)	$ —	$ 17	$ 16,439
Net income	—	—	—	1,863	—	—	—	—	—	1,863
Other Comprehensive Income										
Foreign currency translation adjustments	—	—	—	—	103	—	—	—	—	103
Net unrealized gains on cash flow hedges (b)	—	—	—	—	—	6	—	—	—	6
Reclassification into earnings from cash flow hedges (c)	—	—	—	—	—	36	—	—	—	36
Minimum pension liability adjustment (d)	—	—	—	—	—	—	(1)	—	—	(1)
Other (f)	—	—	—	—	—	—	—	—	(15)	(15)
Total comprehensive income										1,992
Retirement of old Duke Energy shares	(927)	(10,399)	—	—	—	—	—	—	—	(10,399)
Issuance of new Duke Energy shares	927	1	10,398	—	—	—	—	—	—	10,399
Common stock issued in connection with Cinergy merger	313	—	8,993	—	—	—	—	—	—	8,993
Conversion of Cinergy options to Duke Energy options	—	—	59	—	—	—	—	—	—	59
Dividend reinvestment and employee benefits	6	22	172	—	—	—	—	—	—	194
Stock repurchase	(17)	(69)	(431)	—	—	—	—	—	—	(500)
Common stock dividends	—	—	—	(1,488)	—	—	—	—	—	(1,488)
Conversion of debt to equity	27	—	632	—	—	—	—	—	—	632
Tax benefit due to conversion of debt to equity	—	—	34	—	—	—	—	—	—	34
Adjustment due to *SFAS No. 158 adoption (e)*	—	—	—	—	—	—	61	(311)	—	(250)
Other capital stock transactions, net	—	—	(3)	—	—	—	—	—	—	(3)
Balance December 31, 2006	1,257	$ 1	$ 19,854	$ 5,652	$949	$ (45)	$ —	$ (311)	$ 2	$ 26,102

(a) Foreign currency translation adjustments, net of $62 tax benefit in 2005. The 2005 tax benefit related to the settled net investment hedges (see Note 8). Substantially all of the 2005 tax benefit is a correction of an immaterial accounting error related to prior periods.

(b) Net unrealized gains on cash flow hedges, net of $3 tax expense in 2006, $233 tax expense in 2005, and $170 tax expense in 2004.

(c) Reclassification into earnings from cash flow hedges, net of $19 tax expense in 2006, $583 tax benefit in 2005, and $45 tax benefit in 2004. Reclassification into earnings from cash flow hedges in 2006, is due primarily to the recognition of Duke Energy North America's (DENA) unrealized net gains related to hedges on forecasted transactions which will no longer occur as a result of the sale to LS Power of substantially all of DENA's assets and contracts outside of the Midwestern United States and certain contractual positions related to the Midwestern assets (see Notes 8 and 13).

(d) Minimum pension liability adjustment, net of $0 tax benefit in 2006, $228 tax expense in 2005, and $18 tax expense in 2004.

(e) Adjustment due to SFAS No. 158 adoption, net of $144 tax benefit in 2006. Excludes $595 recorded as a regulatory asset (see Note 22).

(f) Net of $9 tax benefit in 2006, and $10 tax expense in 2005.

See Notes to Consolidated Financial Statements

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements

For the Years Ended December 31, 2006, 2005 and 2004

1. Summary of Significant Accounting Policies

Nature of Operations and Basis of Consolidation. Duke Energy Corporation (collectively with its subsidiaries, Duke Energy), is an energy company located in the Americas. These Consolidated Financial Statements include, after eliminating intercompany transactions and balances, the accounts of Duke Energy and all majority-owned subsidiaries where Duke Energy has control, and those variable interest entities where Duke Energy is the primary beneficiary. These Consolidated Financial Statements also reflect Duke Energy's proportionate share of certain generation and transmission facilities in North Carolina and the Midwest.

Duke Energy Holding Corp. (Duke Energy HC) was incorporated in Delaware on May 3, 2005 as Deer Holding Corp., a wholly-owned subsidiary of Duke Energy Corporation (Old Duke Energy). On April 3, 2006, in accordance with their previously announced merger agreement, Old Duke Energy and Cinergy Corp. (Cinergy) merged into wholly-owned subsidiaries of Duke Energy HC, resulting in Duke Energy HC becoming the parent entity. In connection with the closing of the merger transactions, Duke Energy HC changed its name to Duke Energy Corporation (New Duke Energy or Duke Energy) and Old Duke Energy converted into a limited liability company named Duke Power Company LLC (subsequently renamed Duke Energy Carolinas, LLC (Duke Energy Carolinas) effective October 1, 2006). As a result of the merger transactions, each outstanding share of Cinergy common stock was converted into 1.56 shares of common stock of Duke Energy, which resulted in the issuance of approximately 313 million shares. Additionally, each share of common stock of Old Duke Energy was converted into one share of Duke Energy common stock. Old Duke Energy is the predecessor of Duke Energy for purposes of U.S. securities regulations governing financial statement filing. Therefore, the accompanying Consolidated Financial Statements reflect the results of operations of Old Duke Energy for the three months ended March 31, 2006 and the years ended December 31, 2005 and 2004 and the financial position of Old Duke Energy as of December 31, 2005. New Duke Energy had separate operations for the period beginning with the effective date of the Cinergy merger, and references to amounts for periods after the closing of the merger relate to New Duke Energy. Cinergy's results have been included in the accompanying Consolidated Statements of Operations from the effective date of acquisition and thereafter (see "Cinergy Merger" in Note 2). Both Old Duke Energy and New Duke Energy are referred to as Duke Energy herein.

Shares of common stock of New Duke Energy carry a stated par value of $0.001, while shares of common stock of Old Duke Energy had been issued at no par. In April 2006, as a result of the conversion of all outstanding shares of Old Duke Energy common stock to New Duke Energy common stock, the par value of the shares issued was recorded in Common Stock within Common Stockholders' Equity in the Consolidated Balance Sheets and the excess of issuance price over stated par value was recorded in Additional Paid-in Capital within Common Stockholders' Equity in the Consolidated Balance Sheets. Prior to the conversion of common stock from shares of Old Duke Energy to New Duke Energy, all proceeds from issuances of common stock were solely reflected in Common Stock within Common Stockholders' Equity in the Consolidated Balance Sheets.

On September 7, 2006, Duke Energy deconsolidated Crescent Resources, LLC (Crescent) due to a reduction in ownership and its inability to exercise control over Crescent (see Note 2). Crescent has been accounted for as an equity method investment since the date of deconsolidation.

Effective July 1, 2005, Duke Energy has deconsolidated DCP Midstream, LLC (formerly Duke Energy Field Services, LLC) (DEFS) due to a reduction in ownership and its inability to exercise control over DEFS (see Note 2). DEFS has been subsequently accounted for as an equity method investment.

On January 2, 2007, Duke Energy completed the spin-off of its natural gas businesses, including Duke Energy's 50% interest in DEFS, to shareholders. The new natural gas business, which is named Spectra Energy Corp. (Spectra Energy), consists principally of the operations of Spectra Energy Capital LLC (Spectra Energy Capital, formerly Duke Capital LLC), excluding certain operations which were transferred from Spectra Energy Capital to Duke Energy in December 2006, primarily International Energy and Duke Energy's effective 50% interest in the Crescent JV. The use of the term Spectra Energy Capital relates to operations of the former Duke Capital LLC or the post-spin Spectra Energy Capital, as the context requires. Amounts contained in these Notes, as well as the accompanying Consolidated Financial Statements, include assets and liabilities, results of operations and cash flows, as well as certain litigation matters and guarantee obligations, which have been transferred to Spectra Energy as part of the spin-off.

Use of Estimates. To conform to generally accepted accounting principles (GAAP) in the United States, management makes estimates and assumptions that affect the amounts reported in the Consolidated Financial Statements and Notes. Although these estimates are based on management's best available knowledge at the time, actual results could differ.

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

Reclassifications and Revisions. Certain prior period amounts have been reclassified within the Consolidated Statements of Cash Flows to conform to current year presentation.

Cash and Cash Equivalents. All highly liquid investments with original maturities of three months or less at the date of acquisition are considered cash equivalents.

Restricted Funds Held in Trust. At December 31, 2006, Duke Energy had approximately $212 million of restricted cash related primarily to proceeds from debt issuances that are held in trust, primarily for the purpose of funding future environmental expenditures. This amount is reflected in Other Investments and Other Assets on the Consolidated Balance Sheets.

Short-term Investments. Duke Energy actively invests a portion of its available cash balances in various financial instruments, such as tax-exempt debt securities that frequently have stated maturities of 20 years or more and tax-exempt money market preferred securities. These instruments provide for a high degree of liquidity through features such as daily and seven day notice put options and 7, 28, and 35 day auctions which allow for the redemption of the investments at their face amounts plus earned income. As Duke Energy intends to sell these instruments within one year or less, generally within 30 days from the balance sheet date, they are classified as current assets. Duke Energy has classified all short-term investments that are debt securities as available-for-sale under Statement of Financial Accounting Standards (SFAS) No. 115, "Accounting For Certain Investments in Debt and Equity Securities," (SFAS No. 115), and they are carried at fair market value. Investments in money-market preferred securities that do not have stated redemptions are accounted for at their cost, as the carrying values approximate market values due to their short-term maturities and no credit risk. Realized gains and losses and dividend and interest income related to these securities, including any amortization of discounts or premiums arising at acquisition, are included in earnings as incurred. Purchases and sales of available-for-sale securities are presented on a gross basis within Investing Cash Flows in the accompanying Consolidated Statements of Cash Flows.

Inventory. Inventory consists primarily of materials and supplies and natural gas held in storage for transmission, processing and sales commitments; and coal held for electric generation. Inventory is recorded at the lower of cost or market value, primarily using the average cost method. The increase in inventory at December 31, 2006 as compared to December 31, 2005 is primarily attributable to inventory acquired as part of the merger with Cinergy.

Components of Inventory

	December 31,	
	2006	2005
	(in millions)	
Materials and supplies	$ 586	$434
Natural gas	290	269
Coal held for electric generation	383	115
Petroleum products	99	45
Total Inventory	$1,358	$863

Accounting for Risk Management and Hedging Activities and Financial Instruments. Duke Energy uses a number of different derivative and non-derivative instruments in connection with its commodity price, interest rate and foreign currency risk management activities and its trading activities, including swaps, futures, forwards, options and swaptions. All derivative instruments not designated and qualifying for the normal purchases and normal sales exception under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" (SFAS No. 133), as amended, are recorded on the Consolidated Balance Sheets at their fair value as Unrealized Gains or Unrealized Losses on Mark-to-Market and Hedging Transactions. Cash inflows and outflows related to derivative instruments, except those that contain financing elements and those related to net investment hedges and other investing activities, are a component of operating cash flows in the accompanying Consolidated Statements of Cash Flows. Cash inflows and outflows related to derivative instruments containing financing elements are a component of financing cash flows in the accompanying Consolidated Statements of Cash Flows while cash inflows and outflows related to net investment hedges and derivatives related to other investing activities are a component of investing cash flows in the accompanying Consolidated Statements of Cash Flows.

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

Duke Energy designates all energy commodity derivatives as either trading or non-trading. Gains and losses for all derivative contracts that do not represent physical delivery contracts are reported on a net basis in the Consolidated Statements of Operations. For each of the Duke Energy's physical delivery contracts that are derivatives, the accounting model and presentation of gains and losses, or revenue and expense in the Consolidated Statements of Operations is shown below

Classification of Contract	Duke Energy Accounting Model	Presentation of Gains & Losses or Revenue & Expense
Trading derivatives	Mark-to-market[(a)]	Net basis in Non-regulated Electric, Natural Gas, Natural Gas Liquids (NGL), and Other
Non-trading derivatives:		
Cash flow hedge	Accrual[(b)]	Gross basis in the same income statement category as the related hedged item
Fair value hedge	Accrual[(b)]	Gross basis in the same income statement category as the related hedged item
Normal purchase or sale	Accrual[(b)]	Gross basis upon settlement in the corresponding income statement category based on commodity type
Undesignated	Mark-to-market[(a)]	Net basis in the related income statement category for interest rate, currency and commodity derivatives

(a) An accounting term used by Duke Energy to refer to derivative contracts for which an asset or liability is recognized at fair value and the change in the fair value of that asset or liability is recognized in the Consolidated Statements of Operations, with the exception of Union Gas Limited's (Union Gas) regulated business, which is recognized as a regulatory asset or liability. This term is applied to trading and undesignated non-trading derivative contracts. As this term is not explicitly defined within GAAP, Duke Energy's application of this term could differ from that of other companies.

(b) An accounting term used by Duke Energy to refer to contracts for which there is generally no recognition in the Consolidated Statements of Operations for any changes in fair value until the service is provided, the associated delivery period occurs or there is hedge ineffectiveness. As discussed further below, this term is applied to derivative contracts that are accounted for as cash flow hedges, fair value hedges, and normal purchases or sales, as well as to non-derivative contracts used for commodity risk management purposes. As this term is not explicitly defined within GAAP, Duke Energy's application of this term could differ from that of other companies.

Where Duke Energy's derivative instruments are subject to a master netting agreement and the criteria of the Financial Accounting Standards Board (FASB) Interpretation (FIN) No. 39, "Offsetting of Amounts Related to Certain Contracts—An Interpretation of Accounting Principles Board (APB) Opinion No. 10 and FASB Statement No. 105" (FIN 39), are met, Duke Energy presents its derivative assets and liabilities, and accompanying receivables and payables, on a net basis in the accompanying Consolidated Balance Sheets.

Cash Flow and Fair Value Hedges. Qualifying energy commodity and other derivatives may be designated as either a hedge of a forecasted transaction or future cash flows (cash flow hedge) or a hedge of a recognized asset, liability or firm commitment (fair value hedge). For all hedge contracts, Duke Energy prepares formal documentation of the hedge in accordance with SFAS No. 133. In addition, at inception and every three months, Duke Energy formally assesses whether the hedge contract is highly effective in offsetting changes in cash flows or fair values of hedged items. Duke Energy documents hedging activity by transaction type (futures/swaps) and risk management strategy (commodity price risk/interest rate risk).

Changes in the fair value of a derivative designated and qualified as a cash flow hedge, to the extent effective, are included in the Consolidated Statements of Common Stockholders' Equity and Comprehensive Income (Loss) as Accumulated Other Comprehensive Income (Loss) (AOCI) until earnings are affected by the hedged transaction. Duke Energy discontinues hedge accounting prospectively when it has determined that a derivative no longer qualifies as an effective hedge, or when it is no longer probable that the hedged forecasted transaction will occur. When hedge accounting is discontinued because the derivative no longer qualifies as an effective hedge, the derivative is subject to the Mark-to-Market Model of Accounting (MTM Model) prospectively. Gains and losses related to discontinued hedges that were previously accumulated in AOCI will remain in AOCI until the underlying contract is reflected in earnings; unless it is probable that the hedged forecasted transaction will not occur at which time associated deferred amounts in AOCI are immediately recognized in current earnings.

For derivatives designated as fair value hedges, Duke Energy recognizes the gain or loss on the derivative instrument, as well as the offsetting loss or gain on the hedged item in earnings, to the extent effective, in the current period. All derivatives designated and accounted for as hedges are classified in the same category as the item being hedged in the Consolidated Statements of Cash Flows. In addition, all components of each derivative gain or loss are included in the assessment of hedge effectiveness.

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

Normal Purchases and Normal Sales. On a limited basis, Duke Energy Carolinas and Duke Energy Ohio apply the normal purchase and normal sales exception to certain contracts. If contracts cease to meet this exception, the fair value of the contracts is recognized on the Consolidated Balance Sheets and the contracts are accounted for using the MTM Model unless immediately designated as a cash flow or fair value hedge.

As a result of the September 2005 decision to pursue the sale or other disposition of substantially all of Duke Energy North America's (DENA's) remaining physical and commercial assets outside the Midwestern United States, Duke Energy discontinued hedge accounting for forward natural gas and power contracts accounted for as cash flow hedges related to the former DENA operations and disqualified other forward power contracts previously designated under the normal purchases normal sales exception effective September 2005.

Valuation. When available, quoted market prices or prices obtained through external sources are used to measure a contract's fair value. For contracts with a delivery location or duration for which quoted market prices are not available, fair value is determined based on internally developed valuation techniques or models. For derivatives recognized under the MTM Model, valuation adjustments are also recognized in the Consolidated Statements of Operations.

Goodwill. Duke Energy evaluates goodwill for potential impairment under the guidance of SFAS No. 142, "Goodwill and Other Intangible Assets" (SFAS No. 142). Under this provision, goodwill is subject to an annual test for impairment. Duke Energy has designated August 31 as the date it performs the annual review for goodwill impairment for its reporting units. Under the provisions of SFAS No. 142, Duke Energy performs the annual review for goodwill impairment at the reporting unit level, which Duke Energy has determined to be an operating segment or one level below.

Impairment testing of goodwill consists of a two-step process. The first step involves a comparison of the implied fair value of a reporting unit with its carrying amount. If the carrying amount of the reporting unit exceeds its fair value, the second step of the process involves a comparison of the fair value and carrying value of the goodwill of that reporting unit. If the carrying value of the goodwill of a reporting unit exceeds the implied fair value of that goodwill, an impairment loss is recognized in an amount equal to the excess. Additional impairment tests are performed between the annual reviews if events or changes in circumstances make it more likely than not that the fair value of a reporting unit is below its carrying amount.

Duke Energy primarily uses a discounted cash flow analysis to determine fair value. Key assumptions in the determination of fair value include the use of an appropriate discount rate, estimated future cash flows and an estimated run rates of operation, maintenance, and general and administrative costs. In estimating cash flows, Duke Energy incorporates expected growth rates, regulatory stability and ability to renew contracts as well as other factors into its revenue and expense forecasts.

Other Long-term Investments. Other long-term investments, primarily marketable securities held in the Nuclear Decommissioning Trust Funds (NDTF) and the captive insurance investment portfolio, are classified as available-for-sale securities as management does not have the intent or ability to hold the securities to maturity, nor are they bought and held principally for selling them in the near term. The securities are reported at fair value on Duke Energy's Consolidated Balance Sheets. Unrealized and realized gains and losses, net of tax, on the NDTF are reflected in regulatory assets or liabilities on Duke Energy's Consolidated Balance Sheets as Duke Energy expects to recover all costs for decommissioning its nuclear generation assets through regulated rates. Unrealized holding gains and losses, net of tax, on all other available-for-sale securities are reflected in AOCI in Duke Energy's Consolidated Balance Sheets until they are realized, at which time they are reflected in earnings. Cash flows from purchases and sales of long-term investments (including the NDTF) are presented on a gross basis within investing cash flows in the accompanying Consolidated Statements of Cash Flows.

Property, Plant and Equipment. Property, plant and equipment are stated at the lower of historical cost less accumulated depreciation or fair value, if impaired. Duke Energy capitalizes all construction-related direct labor and material costs, as well as indirect construction costs. Indirect costs include general engineering, taxes and the cost of funds used during construction. The cost of renewals and betterments that extend the useful life of property, plant and equipment is also capitalized. The cost of repairs, replacements and major maintenance projects, which do not extend the useful life or increase the expected output of property, plant and equipment, is expensed as it is incurred. Depreciation is generally computed over the asset's estimated useful life using the straight-line method. The composite weighted-average depreciation rates, excluding nuclear fuel, were 3.51% for 2006, 3.34% for 2005, and 3.49% for 2004. Also, see "Deferred Returns and Allowance for Funds Used During Construction (AFUDC)," discussed below.

When Duke Energy retires its regulated property, plant and equipment, it charges the original cost plus the cost of retirement, less salvage value, to accumulated depreciation and amortization. When it sells entire regulated operating units, or retires or sells non-regulated properties, the cost is removed from the property account and the related accumulated depreciation and amortization accounts are reduced. Any gain or loss is recorded in earnings, unless otherwise required by the applicable regulatory body.

Duke Energy recognizes asset retirement obligations (ARO's) in accordance with SFAS No. 143, "Accounting For Asset Retirement Obligations" (SFAS No. 143), for legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or normal use of the asset and FIN No. 47, "Accounting for Conditional Asset Retirement Obligations" (FIN 47), for conditional ARO's in which the timing or method of settlement are conditional on a future event that may or may not be within the control of Duke Energy. Both SFAS No. 143 and FIN 47 require that the fair value of a liability for an ARO be recognized in the period in which it is incurred, if a reasonable estimate of fair value can be made. The fair value of the liability is added to the carrying amount of the associated asset. This additional carrying amount is then depreciated over the estimated useful life of the asset.

Investments in Residential, Commercial, and Multi-Family Real Estate. Prior to the deconsolidation of Crescent in September 2006, investments in residential, commercial and multi-family real estate were carried at cost, net of any related depreciation, except for any properties meeting the criteria in SFAS No. 144, "Accounting for the Impairment or Disposal of Long-lived Assets" (SFAS No. 144), to be presented as Assets Held for Sale, which are carried at lower of cost or fair value less costs to sell in the Consolidated Balance Sheets. Proceeds from sales of residential properties are presented within Operating Revenues and the cost of properties sold are included in Operation, Maintenance and Other in the Consolidated Statements of Operations. Cash flows related to the acquisition, development and disposal of residential properties are included in Cash Flows from Operating Activities in the Consolidated Statements of Cash Flows. Gains and losses on sales of commercial and multi-family properties as well as "legacy" land sales are presented as such in the Consolidated Statements of Operations, and cash flows related to these activities are included in Cash Flows from Investing Activities in the Consolidated Statements of Cash Flows.

Long-Lived Asset Impairments, Assets Held For Sale and Discontinued Operations. Duke Energy evaluates whether long-lived assets, excluding goodwill, have been impaired when circumstances indicate the carrying value of those assets may not be recoverable. For such long-lived assets, an impairment exists when its carrying value exceeds the sum of estimates of the undiscounted cash flows expected to result from the use and eventual disposition of the asset. When alternative courses of action to recover the carrying amount of a long-lived asset are under consideration, a probability-weighted approach is used for developing estimates of future undiscounted cash flows. If the carrying value of the long-lived asset is not recoverable based on these estimated future undiscounted cash flows, the impairment loss is measured as the excess of the asset's carrying value over its fair value, such that the asset's carrying value is adjusted to its estimated fair value.

Management assesses the fair value of long-lived assets using commonly accepted techniques, and may use more than one source. Sources to determine fair value include, but are not limited to, recent third party comparable sales, internally developed discounted cash flow analysis and analysis from outside advisors. Significant changes in market conditions resulting from events such as changes in commodity prices or the condition of an asset, or a change in management's intent to utilize the asset would generally require management to re-assess the cash flows related to the long-lived assets.

Duke Energy uses the criteria in SFAS No. 144 to determine when an asset is classified as "held for sale." Upon classification as "held for sale," the long-lived asset or asset group is measured at the lower of its carrying amount or fair value less cost to sell, depreciation is ceased and the asset or asset group is separately presented on the Consolidated Balance Sheets. When an asset or asset group meets the SFAS No. 144 criteria for classification as held for sale within the Consolidated Balance Sheets, Duke Energy does not retrospectively adjust prior period balance sheets to conform to current year presentation.

Duke Energy uses the criteria in SFAS No. 144 and EITF 03-13, "Applying the Conditions in Paragraph 42 of FASB Statement No. 144 in Determining Whether to Report Discontinued Operations" (EITF 03-13), to determine whether components of Duke Energy that are being disposed of or are classified as held for sale are required to be reported as discontinued operations in the Consolidated Statements of Operations. To qualify as a discontinued operation under SFAS No. 144, the component being disposed of must have clearly distinguishable operations and cash flows. Additionally, pursuant to EITF 03-13, Duke Energy must not have significant continuing involvement in the operations after the disposal (i.e. Duke Energy must not have the ability to influence the operating or financial policies of the disposed component) and cash flows of the operations being disposed of must have been eliminated from Duke Energy's ongoing operations (i.e. Duke Energy does not expect to generate significant direct cash flows from activities involving the disposed component after the disposal transaction is completed). Assuming both preceding conditions are met, the related results of operations for the current and prior periods, including any related impairments, are reflected as (Loss) Income From Discontinued Operations, net of tax, in the Consolidated Statements of Operations. If an asset held for sale does not meet the requirements for discontinued operations classification,

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

any impairments and gains or losses on sales are recorded in continuing operations as Gains (Losses) on Sales of Other Assets and Other, net, in the Consolidated Statements of Operations. Impairments for all other long-lived assets, excluding goodwill, are recorded as Impairment and Other Charges in the Consolidated Statements of Operations.

Captive Insurance Reserves. Duke Energy has captive insurance subsidiaries which provide insurance coverage to Duke Energy entities as well as certain third parties, on a limited basis, for various business risks and losses, such as workers compensation, property, business interruption and general liability. Liabilities include provisions for estimated losses incurred, but not yet reported (IBNR), as well as provisions for known claims which have been estimated on a claims-incurred basis. IBNR reserve estimates involve the use of assumptions and are primarily based upon historical loss experience, industry data and other actuarial assumptions. Reserve estimates are adjusted in future periods as actual losses differ from historical experience. Intercompany balances and transactions are eliminated in consolidation.

Duke Energy's captive insurance entities also have reinsurance coverage, which provides reimbursement to Duke Energy for certain losses above a per incident and/or aggregate retention. Duke Energy's captive insurance entities also have an aggregate stop-loss insurance coverage, which provides reimbursement from third parties to Duke Energy for its paid losses above certain per line of coverage aggregate amounts during a policy year. Duke Energy recognizes a reinsurance receivable for recovery of incurred losses under its captive's reinsurance and stop-loss insurance coverage once realization of the receivable is deemed probable by its captive insurance companies.

During 2004, Duke Energy eliminated intercompany reserves at its captive insurance subsidiaries of approximately $64 million which was a correction of an immaterial accounting error related to prior periods.

Unamortized Debt Premium, Discount and Expense. Premiums, discounts and expenses incurred with the issuance of outstanding long-term debt are amortized over the terms of the debt issues. Any call premiums or unamortized expenses associated with refinancing higher-cost debt obligations to finance regulated assets and operations are amortized consistent with regulatory treatment of those items, where appropriate.

Environmental Expenditures. Duke Energy expenses environmental expenditures related to conditions caused by past operations that do not generate current or future revenues. Environmental expenditures related to operations that generate current or future revenues are expensed or capitalized, as appropriate. Liabilities are recorded when the necessity for environmental remediation becomes probable and the costs can be reasonably estimated, or when other potential environmental liabilities are reasonably estimable and probable.

Cost-Based Regulation. Duke Energy accounts for certain of its regulated operations under the provisions of SFAS No. 71, "Accounting for Certain Types of Regulation" (SFAS No. 71). The economic effects of regulation can result in a regulated company recording assets for costs that have been or are expected to be approved for recovery from customers or recording liabilities for amounts that are expected to be returned to customers in the rate-setting process in a period different from the period in which the amounts would be recorded by an unregulated enterprise. Accordingly, Duke Energy records assets and liabilities that result from the regulated ratemaking process that would not be recorded under GAAP for non-regulated entities. Management continually assesses whether regulatory assets are probable of future recovery by considering factors such as applicable regulatory changes, recent rate orders applicable to other regulated entities and the status of any pending or potential deregulation legislation. Based on this continual assessment, management believes the existing regulatory assets are probable of recovery. These regulatory assets and liabilities are primarily classified in the Consolidated Balance Sheets as Regulatory Assets and Deferred Debits, and Deferred Credits and Other Liabilities. Duke Energy periodically evaluates the applicability of SFAS No. 71, and considers factors such as regulatory changes and the impact of competition. If cost-based regulation ends or competition increases, Duke Energy may have to reduce its asset balances to reflect a market basis less than cost and write-off their associated regulatory assets and liabilities. (For further information see Note 4.)

Guarantees. Duke Energy accounts for guarantees and related contracts, for which it is the guarantor, under FIN No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others" (FIN 45). In accordance with FIN 45, upon issuance or modification of a guarantee on or after January 1, 2003, Duke Energy recognizes a liability at the time of issuance or material modification for the estimated fair value of the obligation it assumes under that guarantee, if any. Fair value is estimated using a probability-weighted approach. Duke Energy reduces the obligation over the term of the guarantee or related contract in a systematic and rational method as risk is reduced under the obligation. Any additional contingent loss for guarantee contracts outside the scope of FIN 45 is accounted for and recognized in accordance with SFAS No. 5, "Accounting for Contingencies" (SFAS No. 5).

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

Duke Energy has entered into various indemnification agreements related to purchase and sale agreements and other types of contractual agreements with vendors and other third parties. These agreements typically cover environmental, tax, litigation and other matters, as well as breaches of representations, warranties and covenants. Typically, claims may be made by third parties for various periods of time, depending on the nature of the claim. Duke Energy's potential exposure under these indemnification agreements can range from a specified to an unlimited dollar amount, depending on the nature of the claim and the particular transaction (see Note 18).

Stock-Based Compensation. Effective January 1, 2006, Duke Energy adopted the provisions of SFAS No. 123(R), "Share-Based Payment" (SFAS No. 123(R)) (see Note 20). SFAS No. 123(R) establishes accounting for stock-based awards exchanged for employee and certain non-employee services. Accordingly, for employee awards, equity classified stock-based compensation cost is measured at the grant date, based on the fair value of the award, and is recognized as expense over the requisite service period, which generally begins on the date the award is granted through the earlier of the date the award vests or the date the employee becomes retirement eligible. Awards, including stock options, granted to employees that are already retirement eligible are deemed to have vested immediately upon issuance, and therefore, compensation cost for those awards is recognized on the date such awards are granted.

Duke Energy elected to adopt the modified prospective application method as provided by SFAS No. 123(R), and accordingly, financial statement amounts periods prior to January 1, 2006 in this Form 10-K have not been restated. There were no modifications to outstanding stock options prior to the adoption of SFAS 123(R).

Duke Energy previously applied Accounting Principles Board (APB) Opinion No. 25, "Accounting for Stock Issued to Employees," and FIN 44, "Accounting for Certain Transactions Involving Stock Compensation (an Interpretation of APB Opinion 25)" and provided the required pro forma disclosures of SFAS No. 123, "Accounting for Stock-Based Compensation" (SFAS No. 123). Since the exercise price for all stock options granted under those plans was equal to the market value of the underlying common stock on the grant date, no compensation cost was recognized in the accompanying Consolidated Statements of Operations.

Revenue Recognition. Revenues on sales of electricity, primarily at U.S. Franchised Electric and Gas, are recognized when the service is provided. Unbilled revenues are estimated by applying an average revenue/kilowatt hour for all customer classes to the number of estimated kilowatt hours delivered, but not billed. Differences between actual and estimated unbilled revenues are immaterial.

Revenues on sales of natural gas, natural gas transportation, storage and distribution as well as sales of petroleum products, primarily at Natural Gas Transmission and Field Services (prior to deconsolidation on July 1, 2005), are recognized when either the service is provided or the product is delivered. Revenues related to these services provided or products delivered, but not yet billed, are estimated each month. These estimates are generally based on contract data, regulatory information, estimated distribution usage based on historical data adjusted for heating degree days, commodity prices and preliminary throughput and allocation measurements. Final bills for the current month are billed and collected in the following month. Differences between actual and estimated unbilled revenues are immaterial.

Crescent sells residential developed lots in North Carolina, South Carolina, Georgia, Florida, Texas and Arizona. Crescent recognizes revenues from the sale of residential developed lots at closing. Prior to the deconsolidation of Crescent in September 2006, profit was recognized under the full accrual method using estimates of average gross profit per lot within a project or phase of a project based on total estimated project costs. Land and land development costs were allocated to land sold based on relative sales values. Crescent recognized revenues from commercial and multi-family project sales at closing, or later using a deferral method when the criteria for sale accounting had not been met at closing. Profit was recognized based on the difference between the sales price and the carrying cost of the project. Revenue was recognized under the completed contract method for condominium units that Crescent developed and sold in Florida.

Nuclear Fuel. Amortization of nuclear fuel purchases is included in the Consolidated Statements of Operations as Fuel Used in Electric Generation and Purchased Power. The amortization is recorded using the units-of-production method.

Deferred Returns and Allowance for Funds Used During Construction (AFUDC). Deferred returns, recorded in accordance with SFAS No. 71, represent the estimated financing costs associated with funding certain regulatory assets or liabilities of U.S. Franchised Electric and Gas. Those costs arise primarily from the funding of purchased capacity costs collected in rates. Deferred returns are non-cash items and are primarily recognized as an addition to purchased capacity costs, which are included in Other Current Liabilities and Other Deferred Credits and Other Liabilities on the Consolidated Balance Sheets, with an offsetting debit or credit to Other Income and Expenses, net. The amount of deferred returns included in Other Income and Expenses, net was ($15) million in 2006, ($13) million in 2005, and ($9) million in 2004.

AFUDC, which represents the estimated debt and equity costs of capital funds necessary to finance the construction of new regulated facilities, consists of two components, an equity component and an interest component. The equity component is a non-cash item. AFUDC is capitalized as a component of Property, Plant and Equipment cost, with offsetting credits to the Consolidated Statements of Operations. After construction is completed, Duke Energy is permitted to recover these costs through inclusion in the rate base and in the depreciation provision. The total amount of AFUDC included in the Consolidated Statements of Operations was $97 million in 2006, which consisted of an after-tax equity component of $58 million and a before-tax interest expense component of $39 million. The total amount of AFUDC included in the Consolidated Statements of Operations was $48 million in 2005, which consisted of an after-tax equity component of $30 million and a before-tax interest expense component of $18 million. The total amount of AFUDC included in the Consolidated Statements of Operations was $39 million in 2004, which consisted of an after-tax equity component of $25 million and a before-tax interest expense component of $14 million.

Accounting For Sales of Stock by a Subsidiary. Duke Energy accounts for sales of stock by a subsidiary under Staff Accounting Bulletin (SAB) No. 51, "Accounting for Sales of Stock of a Subsidiary" (SAB 51). Under SAB 51, companies may elect, via an accounting policy decision, to record a gain on the sale of stock of a subsidiary equal to the amount of proceeds received in excess of the carrying value of the shares. Duke Energy has elected to treat such excesses as gains in earnings, which are reflected in Gain on Sale of Subsidiary Stock in the Consolidated Statements of Operations. During the year ended December 31, 2006, Duke Energy recognized a gain of approximately $15 million related to the sale of securities of the Duke Energy Income Fund (Income Fund) (see Note 11).

Accounting For Purchases and Sales of Emission Allowances. Duke Energy recognizes emission allowances in earnings as they are consumed or sold. Gains or losses on sales of emission allowances for non-regulated businesses are presented on a net basis in Gains (Losses) on Sales of Other Assets and Other, net, in the accompanying Consolidated Statements of Operations. For regulated businesses that do provide for direct recovery of emission allowances, any gains or losses on sales of recoverable emission allowances are included in the rate structure of the regulated entity and are deferred as a regulatory asset or liability. Future rates charged to retail customers are impacted by any gain or loss on sales of recoverable emission allowances and, therefore, as the recovery of the gain or loss is recognized in operating revenues, the regulatory asset or liability related to the emission allowance activity is recognized as a component of Fuel Used in Electric Generation and Purchased Power in the Consolidated Statements of Operations. For regulated businesses that do not provide for direct recovery of emission allowances through a cost tracking mechanism, gains and losses on sales of emission allowances are included in Gains (Losses) on Sales of Other Assets and Other, net in the Consolidated Statements of Operations, or are deferred, depending on level of regulatory certainty. Purchases and sales of emission allowances are presented gross as investing activities on the Consolidated Statements of Cash Flows.

Income Taxes. Duke Energy and its subsidiaries file a consolidated federal income tax return and other state and foreign jurisdictional returns as required. Deferred income taxes have been provided for temporary differences between the GAAP and tax carrying amounts of assets and liabilities. These differences create taxable or tax-deductible amounts for future periods. Investment tax credits have been deferred and are being amortized over the estimated useful lives of the related properties.

Management evaluates and records contingent tax liabilities and related interest based on the probability of ultimately sustaining the tax deductions or income positions. Management assesses the probabilities of successfully defending the tax deductions or income positions based upon statutory, judicial or administrative authority.

Excise Taxes. Certain excise taxes levied by state or local governments are collected by Duke Energy from its customers. These taxes, which are required to be paid regardless of Duke Energy's ability to collect from the customer, are accounted for on a gross basis. When Duke Energy acts as an agent, and the tax is not required to be remitted if it is not collected from the customer, the taxes are accounted for on a net basis. Duke Energy's excise taxes accounted for on a gross basis and recorded as revenues in the accompanying Consolidated Statements of Operations for years ended December 31, 2006, 2005, and 2004 were as follows:

	Year Ended December 31, 2006	Year Ended December 31, 2005	Year Ended December 31, 2004
		(in millions)	
Excise Taxes	$221	$ 121	$ 116

Segment Reporting. SFAS No. 131, "Disclosures about Segments of an Enterprise and Related Information" (SFAS No. 131), establishes standards for a public company to report financial and descriptive information about its reportable operating segments in annual and interim financial reports. Operating segments are components of an enterprise about which separate financial information is available and evaluated regularly by the chief operating decision maker in deciding how to allocate resources and evaluate performance.

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

Two or more operating segments may be aggregated into a single reportable segment provided aggregation is consistent with the objective and basic principles of SFAS No. 131, if the segments have similar economic characteristics, and the segments are considered similar under criteria provided by SFAS No. 131. There is no aggregation within Duke Energy's defined business segments. SFAS No. 131 also establishes standards and related disclosures about the way the operating segments were determined, products and services, geographic areas and major customers, differences between the measurements used in reporting segment information and those used in the general-purpose financial statements, and changes in the measurement of segment amounts from period to period. The description of Duke Energy's reportable segments, consistent with how business results are reported internally to management and the disclosure of segment information in accordance with SFAS No. 131, are presented in Note 3.

Foreign Currency Translation. The local currencies of Duke Energy's foreign operations have been determined to be their functional currencies, except for certain foreign operations whose functional currency has been determined to be the U.S. Dollar, based on an assessment of the economic circumstances of the foreign operation, in accordance with SFAS No. 52, "Foreign Currency Translation." Assets and liabilities of foreign operations, except for those whose functional currency is the U.S. Dollar, are translated into U.S. Dollars at current exchange rates. Translation adjustments resulting from fluctuations in exchange rates are included as a separate component of AOCI. Revenue and expense accounts of these operations are translated at average exchange rates prevailing during the year. Gains and losses arising from transactions denominated in currencies other than the functional currency, which were not material for all periods presented, are included in the results of operations of the period in which they occur. Deferred taxes are not provided on translation gains and losses where Duke Energy expects earnings of a foreign operation to be permanently reinvested. Gains and losses relating to derivatives designated as hedges of the foreign currency exposure of a net investment in foreign operations are reported in foreign currency translation as a separate component of AOCI.

Statements of Consolidated Cash Flows. Duke Energy has made certain classification elections within its Consolidated Statements of Cash Flows related to discontinued operations, cash received from insurance proceeds and cash overdrafts. Cash flows from discontinued operations are combined with cash flows from continuing operations within operating, investing and financing cash flows within the Consolidated Statements of Cash Flows. Cash received from insurance proceeds are classified depending on the activity that resulted in the insurance proceeds (for example, business interruption insurance proceeds are included as a component of operating activities while insurance proceeds from damaged property are included as a component of investing activities). With respect to cash overdrafts, book overdrafts are included within operating cash flows while bank overdrafts are included within financing cash flows.

Distributions from Equity Investees. Duke Energy considers dividends received from equity investees which do not exceed cumulative equity in earnings subsequent to the date of investment a return on investment and classifies these amounts as operating activities within the accompanying Consolidated Statements of Cash Flows. Cumulative dividends received in excess of cumulative equity in earnings subsequent to the date of investment are considered a return of investment and are classified as investing activities within the accompanying Consolidated Statements of Cash Flows.

Cumulative Effect of Changes in Accounting Principles. As of December 31, 2005, Duke Energy adopted the provisions of FIN 47. In accordance with the transition guidance of this standard, Duke Energy recorded a net-of-tax cumulative effect adjustment of approximately $4 million. The cumulative effect adjustment had an immaterial impact on EPS.

New Accounting Standards. The following new accounting standards were adopted by Duke Energy during the year ended December 31, 2006 and the impact of such adoption, if applicable, has been presented in the accompanying Consolidated Financial Statements:

SFAS No. 123(R) "Share-Based Payment" (SFAS No. 123(R)). In December 2004, the Financial Accounting Standards Board (FASB) issued SFAS No. 123(R), which replaces SFAS No. 123, "Accounting for Stock-Based Compensation," and supersedes APB Opinion No. 25, "Accounting for Stock Issued to Employees." SFAS No. 123(R) requires all share-based payments to employees, including grants of employee stock options, to be recognized in the financial statements based on their fair values. For Duke Energy, timing for implementation of SFAS No. 123(R) was January 1, 2006. The pro forma disclosures previously permitted under SFAS No. 123 are no longer an acceptable alternative. Instead, Duke Energy is required to determine an appropriate expense for stock options and record compensation expense in the Consolidated Statements of Operations for stock options. Duke Energy implemented SFAS No. 123(R) using the modified prospective transition method, which required Duke Energy to record compensation expense for all unvested awards beginning January 1, 2006.

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

Duke Energy currently also has retirement eligible employees with outstanding share-based payment awards (unvested stock awards, stock based performance awards and phantom stock awards). Compensation cost related to those awards was previously expensed over the stated vesting period or until actual retirement occurred. Effective January 1, 2006, Duke Energy is required to recognize compensation cost for new awards granted to employees over the requisite service period, which generally begins on the date the award is granted through the earlier of the date the award vests or the date the employee becomes retirement eligible. Awards, including stock options, granted to employees that are already retirement eligible are deemed to have vested immediately upon issuance, and therefore, compensation cost for those awards is recognized on the date such awards are granted.

The adoption of SFAS No. 123(R) did not have a material impact on Duke Energy's consolidated results of operations, cash flows or financial position in 2006 based on awards outstanding as of the implementation date. However, the impact to Duke Energy in periods subsequent to adoption of SFAS No. 123(R) will be largely dependent upon the nature of any new share-based compensation awards issued to employees. (See Note 20.)

Staff Accounting Bulletin (SAB) No. 107, "Share-Based Payment" (SAB No. 107). On March 29, 2005, the Securities and Exchange Commission (SEC) staff issued SAB No. 107 to express the views of the staff regarding the interaction between SFAS No. 123(R) and certain SEC rules and regulations and to provide the staff's views regarding the valuation of share-based payment arrangements for public companies. Duke Energy adopted SFAS No. 123(R) and SAB No. 107 effective January 1, 2006.

FASB Staff Position (FSP) No. FAS 123(R)-4, "Classification of Options and Similar Instruments Issued as Employee Compensation That Allow for Cash Settlement upon the Occurrence of a Contingent Event" (FSP No. FAS 123(R)-4). In February 2006, the FASB staff issued FSP FAS No. 123(R)-4 to address the classification of options and similar instruments issued as employee compensation that allow for cash settlement upon the occurrence of a contingent event. The guidance amends SFAS No. 123(R). FSP No. FAS 123(R)-4 provides that cash settlement features that can be exercised only upon the occurrence of a contingent event that is outside the employee's control does not require classifying the option or similar instrument as a liability until it becomes probable that the event will occur. FSP No. FAS 123(R)-4 applies only to options or similar instruments issued as part of employee compensation arrangements. The guidance in FSP No. FAS 123(R)-4 was effective for Duke Energy as of April 1, 2006. Duke Energy adopted SFAS No. 123(R) as of January 1, 2006 (see Note 20). The adoption of FSP No. FAS 123(R)-4 did not have a material impact on Duke Energy's consolidated statement of operations, cash flows or financial position.

FSP No. FAS 115-1 and 124-1, "The Meaning of Other-Than-Temporary Impairment and its Application to Certain Investments" (FSP No. FAS 115-1 and 124-1). The FASB issued FSP No. FAS 115-1 and 124-1 in November 2005, which was effective for Duke Energy beginning January 1, 2006. This FSP addresses the determination as to when an investment is considered impaired, whether that impairment is other than temporary, and the measurement of an impairment loss. This FSP also includes accounting considerations subsequent to the recognition of an other-than-temporary impairment and requires certain disclosures about unrealized losses that have not been recognized as other-than-temporary impairments. The guidance in this FSP amends SFAS No. 115, "Accounting for Certain Investments in Debt and Equity Securities," and SFAS No. 124, "Accounting for Certain Investments Held by Not-for-Profit Organizations," and APB Opinion No. 18. The adoption of FSP No. FAS 115-1 and 124-1 did not have a material impact on Duke Energy's consolidated results of operations, cash flows or financial position.

FSP No. FIN 46(R)-6, "Determining the Variability to Be Considered In Applying FASB Interpretation No. 46(R) (FSP No. FIN 46(R)-6)." In April 2006, the FASB staff issued FSP No. FIN 46(R)-6 to address how to determine the variability to be considered in applying FIN 46(R), "Consolidation of Variable Interest Entities." The variability that is considered in applying FIN 46(R) affects the determination of whether the entity is a variable interest entity (VIE), which interests are variable interests in the entity, and which party, if any, is the primary beneficiary of the VIE. The variability affects the calculation of expected losses and expected residual returns. This guidance is effective for all entities with which Duke Energy first becomes involved or existing entities for which a reconsideration event occurs after July 1, 2006. The adoption of FSP No. FIN 46(R)-6 did not have a material impact on Duke Energy's consolidated results of operations, cash flows or financial position.

EITF Issue No. 05-1, "Accounting for the Conversion of an Instrument that Becomes Convertible Upon the Issuer's Exercise of a Call Option" (EITF No. 05-1). In June 2006, the EITF reached a consensus on EITF No. 05-1. The consensus requires that the issuance of equity securities to settle a debt instrument (pursuant to the instrument's original conversion terms) that became convertible upon the issuer's exercise of a call option be accounted for as a conversion if the debt instrument contained a substantive conversion feature as of its issuance date. If the debt instrument did not contain a substantive conversion option as of its issuance date, the issuance of equity securities to settle the debt instrument should be accounted for as a debt extinguishment. The consensus was effective for Duke Energy for all conversions within its scope that resulted from the exercise of call options beginning July 1, 2006. The adoption of EITF No. 05-1 did not have a material impact on Duke Energy's consolidated results of operations, cash flows or financial position.

SFAS No. 158, "Employer's Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R)" (SFAS No. 158). In October 2006, the FASB issued SFAS No. 158, which changes the recognition and disclosure provisions and measurement date requirements for an employer's accounting for defined benefit pension and other postretirement plans. The recognition and disclosure provisions require an employer to (1) recognize the funded status of a benefit plan—measured as the difference between plan assets at fair value and the benefit obligation—in its statement of financial position, (2) recognize as a component of OCI, net of tax, the gains or losses and prior service costs or credits that arise during the period but are not recognized as components of net periodic benefit cost, and (3) disclose in the notes to financial statements certain additional information. SFAS No. 158 does not change the amounts recognized in the income statement as net periodic benefit cost. Duke Energy is required to initially recognize the funded status of its defined benefit pension and other postretirement plans and to provide the required additional disclosures as of December 31, 2006 (see Note 22). Retrospective application is not permitted. The adoption of SFAS No. 158 recognition and disclosure provisions resulted in an increase in total assets of approximately $211 million (consisting of an increase in regulatory assets of $595 million, an increase in deferred tax assets of $144 million, offset by a decrease in pre-funded pension costs of $522 million and a decrease in intangible assets of $6 million), an increase in total liabilities of approximately $461 million and a decrease in accumulated other comprehensive income, net of tax, of approximately $250 million as of December 31, 2006. The adoption of SFAS No. 158 did not have any material impact on Duke Energy's consolidated results of operations or cash flows.

Under the measurement date requirements of SFAS No. 158, an employer is required to measure defined benefit plan assets and obligations as of the date of the employer's fiscal year-end statement of financial position (with limited exceptions). Historically, Duke Energy has measured its plan assets and obligations up to three months prior to the fiscal year-end, as allowed under the authoritative accounting literature. The measurement date requirement is effective for the year ending December 31, 2008, and early application is encouraged. Duke Energy intends to adopt the change in measurement date effective January 1, 2007 by remeasuring plan assets and benefit obligations as of that date, pursuant to the transition requirements of SFAS No. 158. Net periodic benefit cost for the three-month period between September 30, 2006 and December 31, 2006 will be recognized, net of tax, as a separate adjustment of retained earnings as of January 1, 2007. Additionally, changes in plan assets and plan obligations between September 30, 2006 and December 31, 2006 not related to net periodic benefit cost will be recognized, net of tax, as an adjustment to OCI.

SAB No. 108, "Considering the Effects of Prior Year Misstatements When Quantifying Misstatements in Current Year Financial Statements" (SAB No. 108). In September 2006 the SEC issued SAB No. 108, which provides interpretive guidance on how the effects of the carryover or reversal of prior year misstatements should be considered in quantifying a current year misstatement. Traditionally, there have been two widely-recognized approaches for quantifying the effects of financial statement misstatements. The income statement approach focuses primarily on the impact of a misstatement on the income statement—including the reversing effect of prior year misstatements—but its use can lead to the accumulation of misstatements in the balance sheet. The balance sheet approach, on the other hand, focuses primarily on the effect of correcting the period-end balance sheet with less emphasis on the reversing effects of prior year errors on the income statement. The SEC staff believes that registrants should quantify errors using both a balance sheet and an income statement approach (a "dual approach") and evaluate whether either approach results in quantifying a misstatement that, when all relevant quantitative and qualitative factors are considered, is material.

SAB No. 108 was effective for Duke Energy's year ending December 31, 2006. SAB No. 108 permits existing public companies to initially apply its provisions either by (i) restating prior financial statements as if the "dual approach" had always been used or (ii), under certain circumstances, recording the cumulative effect of initially applying the "dual approach" as adjustments to the carrying values of assets and liabilities as of January 1, 2006 with an offsetting adjustment recorded to the opening balance of retained earnings. Duke Energy has historically used a dual approach for quantifying identified financial statement misstatements. Therefore, the adoption of SAB No. 108 did not have any material impact on Duke Energy's consolidated results of operations, cash flows or financial position.

The following new accounting standards were adopted by Duke Energy during the year ended December 31, 2005 and the impact of such adoption, if applicable, has been presented in the accompanying Consolidated Financial Statements:

SFAS No. 153, "Exchanges of Nonmonetary Assets—an amendment of APB Opinion No. 29" (SFAS No. 153). In December 2004, the FASB issued SFAS No. 153 which amends APB Opinion No. 29, "Accounting for Nonmonetary Transactions," by eliminating the exception to the fair-value principle for exchanges of similar productive assets, which were accounted for under APB Opinion No. 29 based on the book value of the asset surrendered with no gain or loss recognition. SFAS No. 153 also eliminates APB Opinion No. 29's concept of culmination of an earnings process. The amendment requires that an exchange of nonmonetary assets be accounted for at fair value if the exchange has commercial substance and fair value is determinable within reasonable limits. Commercial substance is assessed by comparing the entity's expected cash flows immediately before and after the exchange. If the difference is significant, the transaction is considered to have commercial substance and should be recognized at fair value. SFAS No. 153 is effective for nonmonetary transactions occurring on or after July 1, 2005. The adoption of SFAS No. 153 did not have a material impact on Duke Energy's consolidated results of operations, cash flows or financial position.

FASB Interpretation No. (FIN) 47 "Accounting for Conditional Asset Retirement Obligations" (FIN 47). In March 2005, the FASB issued FIN 47, which clarifies the accounting for conditional asset retirement obligations as used in SFAS No. 143, "Accounting for Asset Retirement Obligations," (SFAS No. 143). A conditional asset retirement obligation is an unconditional legal obligation to perform an asset retirement activity in which the timing and (or) method of settlement are conditional on a future event that may or may not be within the control of the entity. Therefore, an entity is required to recognize a liability for the fair value of a conditional asset retirement obligation under SFAS No. 143 if the fair value of the liability can be reasonably estimated. The provisions of FIN 47 were effective for Duke Energy as of December 31, 2005, and resulted in an increase in assets of $31 million, an increase in liabilities of $35 million and a net-of-tax cumulative effect adjustment to earnings of approximately $4 million.

FASB Staff Position (FSP) No. APB 18-1, "Accounting by an Investor for Its Proportionate Share of Accumulated Other Comprehensive Income of an Investee Accounted for under the Equity Method in Accordance with APB Opinion No. 18 upon a Loss of Significant Influence" (FSP No. APB 18-1). In July 2005, the FASB staff issued FSP No. APB 18-1 which provides guidance for how an investor should account for its proportionate share of an investee's equity adjustments for other comprehensive income (OCI) upon a loss of significant influence. APB Opinion No. 18, "The Equity Method of Accounting for Investments in Common Stock" (APB Opinion No. 18), requires a transaction of an equity method investee of a capital nature be accounted for as if the investee were a consolidated subsidiary, which requires the investor to record its proportionate share of the investee's adjustments for OCI as increases or decreases to the investment account with corresponding adjustments in equity. FSP No. APB 18-1 requires that an investor's proportionate share of an investee's equity adjustments for OCI should be offset against the carrying value of the investment at the time significant influence is lost and equity method accounting is no longer appropriate. However, to the extent that the offset results in a carrying value of the investment that is less than zero, an investor should (a) reduce the carrying value of the investment to zero and (b) record the remaining balance in income. The guidance in FSP No. APB 18-1 was effective for Duke Energy beginning October 1, 2005. The adoption of FSP No. APB 18-1 did not have a material impact on Duke Energy's consolidated results of operations, cash flows or financial position.

The following new accounting standards were adopted by Duke Energy during the year ended December 31, 2004 and the impact of such adoption, if applicable, has been presented in the accompanying Consolidated Financial Statements:

FIN 46, "Consolidation of Variable Interest Entities". In January 2003, the FASB issued FIN 46 which requires the primary beneficiary of a variable interest entity's activities to consolidate the variable interest entity. FIN 46 defines a variable interest entity as an entity in which the equity investors do not have substantive voting rights and there is not sufficient equity at risk for the entity to finance its activities without additional subordinated financial support. The primary beneficiary absorbs a majority of the expected losses and/or receives a majority of the expected residual returns of the variable interest entity's activities. In December 2003, the FASB issued FIN 46 (Revised December 2003), "Consolidation of Variable Interest Entities—An Interpretation of ARB No. 51" (FIN 46R), which supersedes and amends the provisions of FIN 46. While FIN 46R retains many of the concepts and provisions of FIN 46, it also provides additional guidance and additional scope exceptions, and incorporates FASB Staff Positions related to the application of FIN 46.

The provisions of FIN 46 applied immediately to variable interest entities created, or interests in variable interest entities obtained, after January 31, 2003, while the provisions of FIN 46R were required to be applied to those entities, except for special purpose entities, by the end of the first reporting period ending after March 15, 2004 (March 31, 2004 for Duke Energy). For variable interest entities created, or interests in variable interest entities obtained, on or before January 31, 2003, FIN 46 or FIN 46R was required to be applied to special-purpose entities by the end of the first reporting period ending after December 15, 2003 (December 31, 2003 for Duke Energy), and was required to be applied to all other non-special purpose entities by the end of the first reporting period ending after March 15, 2004 (March 31, 2004 for Duke Energy).

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

See Note 23 for a discussion of certain variable interest entities acquired by Duke Energy as part of the Cinergy merger. Duke Energy has consolidated certain non-special purpose operating entities, previously accounted for under the equity method of accounting. These entities, which are substantive entities, had an immaterial amount of total assets as of December 31, 2006 and 2005. The impact of consolidating these entities on Duke Energy's consolidated financial statements was not material. In addition, at December 31, 2005, Duke Energy recorded Net Property, Plant and Equipment of $109 million and Long-term Debt of $173 million on the Consolidated Balance Sheets, associated with a natural gas processing variable interest entity that was consolidated by Duke Energy. In 2006, Duke Energy exercised its right to repurchase the assets held by the variable interest entity and repaid the loan.

Various changes and clarifications to the provisions of FIN 46 have been made by the FASB since its original issuance in January 2003. While not anticipated at this time, any additional clarifying guidance or further changes to these complex rules could have an impact on Duke Energy's Consolidated Financial Statements.

SFAS No. 132 (Revised 2003), "Employers' Disclosures about Pensions and Other Postretirement Benefits" (SFAS No. 132R). In December 2003, the FASB revised the provisions of SFAS No. 132, "Employers' Disclosures about Pensions and Other Postretirement Benefits—an amendment of FASB Statements No. 87, 88, and 106," to include additional disclosures related to defined-benefit pension plans and other defined-benefit post-retirement plans, such as the following:

- The long-term rate of return on plan assets, along with a narrative discussion on the basis for selecting the rate of return used
- Information about plan assets for each major asset category (i.e. equity securities, debt securities, real estate, etc.) along with the targeted allocation percentage of plan assets for each category and the actual allocation percentages at the measurement date
- The amount of benefit payments expected to be paid in each of the next five years and the following five-year period in the aggregate
- The current best estimate of the range of contributions expected to be made in the following year
- The accumulated benefit obligation for defined-benefit pension plans
- Disclosure of the measurement date utilized.

Additionally, interim reports require additional disclosures related to the components of net periodic pension costs and the amounts paid or expected to be paid to the plan in the current fiscal year, if materially different than amounts previously disclosed. The provisions of SFAS No. 132R do not change the measurement or recognition provisions of defined-benefit pension and post-retirement plans as required by previous accounting standards. The provisions of SFAS No. 132R were applied by Duke Energy effective December 31, 2003 with the interim period disclosures applied beginning with the quarter ended March 31, 2004, except for the disclosure provisions of estimated future benefit payments which were effective for Duke Energy for the year ended December 31, 2004. (See Note 22 for the additional related disclosures).

FSP No. FAS 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003" (FSP No. FAS 106-2). In May 2004, the FASB staff issued FSP No. FAS 106-2, which superseded FSP FAS 106-1, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003." FSP No. FAS 106-2 provides accounting guidance for the effects of the Medicare Prescription Drug Improvement and Modernization Act of 2003 (the Modernization Act). The Modernization Act introduced a prescription drug benefit under Medicare, as well as a federal subsidy to sponsors of retiree health care benefit plans that include prescription drug benefits. FSP No. FAS 106-2 requires a sponsor to determine if its prescription drug benefits are actuarially equivalent to the drug benefit provided under Medicare Part D as of the date of enactment of the Modernization Act, and if it is therefore entitled to receive the subsidy. If a sponsor determines that its prescription drug benefits are actuarially equivalent to the Medicare Part D benefit, the sponsor should recognize the expected subsidy in the measurement of the accumulated postretirement benefit obligation (APBO) under SFAS No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions." Any resulting reduction in the APBO is to be accounted for as an actuarial experience gain. The subsidy's reduction, if any, of the sponsor's share of future costs under its prescription drug plan is to be reflected in current-period service cost.

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

The provisions of FSP No. FAS 106-2 were effective for the first interim period beginning after June 15, 2004. Duke Energy adopted FSP No. FAS 106-2 retroactively to the date of enactment of the Modernization Act, December 8, 2003, as allowed by the FSP. (See Note 22 for discussion of the effects of adopting this FSP).

FSP No. FAS 109-1, "Application of FASB Statement No. 109, 'Accounting for Income Taxes,' to the Tax Deduction on Qualified Production Activities Provided by the American Jobs Creation Act of 2004" (FSP No. FAS 109-1). On October 22, 2004, the President signed the American Jobs Creation Act of 2004 (the Act). The Act provides a deduction for income from qualified domestic production activities, which will be phased in from 2005 through 2010.

Under the guidance in FSP No. FAS 109-1, which was issued in December 2004, the deduction will be treated as a "special deduction" as described in SFAS No. 109, "Accounting for Income Taxes" (SFAS No. 109). As such, for Duke Energy, the special deduction had no material impact on deferred tax assets and liabilities existing at the enactment date. Rather, the impact of this deduction is reported in the periods in which the deductions are claimed on the tax returns. For the years ended December 31, 2006 and 2005, Duke Energy recognized a benefit of approximately $0 and $9 million, respectively, relating to the deduction from qualified domestic activities.

FSP No. FAS 109-2, "Accounting and Disclosure Guidance for the Foreign Earnings Repatriation Provision within the American Jobs Creation Act of 2004" (FSP No. FAS 109-2). In addition to the qualified domestic production activities deduction discussed above, the Act creates a temporary incentive for U.S. corporations to repatriate accumulated income earned abroad by providing an 85 percent dividends received deduction for certain dividends from controlled foreign corporations. FSP No. FAS 109-2, which was issued in December 2004, states that a company is allowed time beyond the financial reporting period of enactment to evaluate the effect of the Act on its plan for reinvestment or repatriation of foreign earnings, as it applies to the application of SFAS No. 109. Although the deduction is subject to a number of limitations and some uncertainty remains as to how to interpret numerous provisions in the Act, Duke Energy believes that it has the information necessary to make an informed decision on the impact of the Act on its repatriation plans. Based on that decision, Duke Energy has repatriated approximately $500 million in extraordinary dividends, as defined in the Act, and accordingly recorded a corresponding tax liability of $39 million as of December 31, 2005. However, Duke Energy has not provided for U.S. deferred income taxes or foreign withholding tax on basis differences for its non-U.S. subsidiaries that result primarily from undistributed earnings of approximately $420 million as of December 31, 2006 and $290 million as of December 31, 2005, which Duke Energy intends to reinvest indefinitely. Determination of the deferred tax liability on these basis differences is not practicable because such liability, if any, is dependent on circumstances existing if and when remittance occurs.

EITF Issue No. 04-08, "The Effect of Contingently Convertible Debt on Diluted Earnings per Share" (EITF 04-08). In September 2004, the EITF reached a consensus on Issue No. 04-8. The consensus requires that the potential common stock related to contingently convertible securities (Co-Cos) with market price contingencies be included in diluted earnings per share calculations using the if-converted method specified in SFAS No. 128, "Earnings per Share" (SFAS No. 128), whether the market price contingencies have been met or not. Co-Cos generally require conversion into a company's common stock if certain specified events occur, such as a specified market price for the company's common stock. Prior to the issuance of EITF 04-08, Co-Cos were treated as contingently issuable shares under SFAS No. 128, and therefore, the contingencies, must have been met in order for the potential common shares to be included in diluted EPS. Therefore, Co-Cos were only included in diluted EPS during periods in which the contingencies had been met. The consensus is effective for fiscal years ended after December 15, 2004 and is required to be applied retroactively to all periods in which any Co-Cos were outstanding, resulting in restatement of diluted EPS if the impact of the Co-Cos was dilutive.

As discussed in Note 15, Duke Energy issued $770 million par value of contingently convertible notes in May of 2003, bearing an interest rate of 1.75% per annum that contain several contingencies, including a market price contingency that, if met, may require conversion of the notes into Duke Energy common stock. Conversion may be required, at the option of the holder, if any one of the contingencies is met. During 2006 and 2005, these convertible senior notes became convertible into shares of Duke Energy common stock due to the market price of Duke Energy common stock. Holders of the convertible senior notes were allowed to exercise their right to convert on or prior to December 31, 2006. During 2006 and 2005, approximately 27 million and 1.2 million shares of common stock, respectively, were issued related to this conversion, which resulted in the retirement of approximately $632 million and $28 million of convertible senior notes, respectively. Therefore, as discussed in Note 19, Duke Energy has included potential weighted average common shares outstanding of approximately 14 million, 32 million and 33 million for the years ended December 31, 2006, 2005 and 2004, respectively, in the calculation of diluted EPS.

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

The following new accounting standards have been issued, but have not yet been adopted by Duke Energy as of December 31, 2006:

SFAS No. 155, "Accounting for Certain Hybrid Financial Instruments—an amendment of FASB Statements No. 133 and 140" (SFAS No. 155). In February 2006, the FASB issued SFAS No. 155, which amends SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" and SFAS No. 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities." SFAS No. 155 allows financial instruments that have embedded derivatives to be accounted for at fair value at acquisition, at issuance, or when a previously recognized financial instrument is subject to a remeasurement (new basis) event, on an instrument-by-instrument basis, in cases in which a derivative would otherwise have to be bifurcated. SFAS No. 155 is effective for Duke Energy for all financial instruments acquired, issued, or subject to remeasurement after January 1, 2007, and for certain hybrid financial instruments that have been bifurcated prior to the effective date, for which the effect is to be reported as a cumulative-effect adjustment to beginning retained earnings. Duke Energy does not anticipate the adoption of SFAS No. 155 will have any material impact on its consolidated results of operations, cash flows or financial position.

SFAS No. 156, "Accounting for Servicing of Financial Assets—an amendment of FASB Statement No. 140" (SFAS No. 156). In March 2006, the FASB issued SFAS No. 156, which amends SFAS No. 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities." SFAS No. 156 requires recognition of a servicing asset or liability when an entity enters into arrangements to service financial instruments in certain situations. Such servicing assets or servicing liabilities are required to be initially measured at fair value, if practicable. SFAS No. 156 also allows an entity to subsequently measure its servicing assets or servicing liabilities using either an amortization method or a fair value method. SFAS No. 156 is effective for Duke Energy as of January 1, 2007, and must be applied prospectively, except that where an entity elects to remeasure separately recognized existing arrangements and reclassify certain available-for-sale securities to trading securities, any effects must be reported as a cumulative-effect adjustment to retained earnings. Duke Energy does not anticipate the adoption of SFAS No. 156 will have any material impact on its consolidated results of operations, cash flows or financial position.

SFAS No. 157, "Fair Value Measurements" (SFAS No. 157). In September 2006, the FASB issued SFAS No. 157, which defines fair value, establishes a framework for measuring fair value in GAAP, and expands disclosures about fair value measurements. SFAS No. 157 does not require any new fair value measurements. However, in some cases, the application of SFAS No. 157 may change Duke Energy's current practice for measuring and disclosing fair values under other accounting pronouncements that require or permit fair value measurements. For Duke Energy, SFAS No. 157 is effective as of January 1, 2008 and must be applied prospectively except in certain cases. Duke Energy is currently evaluating the impact of adopting SFAS No. 157, and cannot currently estimate the impact of SFAS No. 157 on its consolidated results of operations, cash flows or financial position.

SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities" (SFAS No. 159). In February 2007, the FASB issued SFAS No. 159, which permits entities to choose to measure many financial instruments and certain other items at fair value. For Duke Energy, SFAS No. 159 is effective as of January 1, 2008 and will have no impact on amounts presented for periods prior to the effective date. Duke Energy cannot currently estimate the impact of SFAS No. 159 on its consolidated results of operations, cash flows or financial position and has not yet determined whether or not it will choose to measure items subject to SFAS No. 159 at fair value.

FIN 48, "Accounting for Uncertainty in Income Taxes—an interpretation of FASB Statement No. 109". In July 2006, the FASB issued FIN 48, which provides guidance on accounting for income tax positions about which Duke Energy has concluded there is a level of uncertainty with respect to the recognition in Duke Energy's financial statements. FIN 48 prescribes a minimum recognition threshold a tax position is required to meet. Tax positions are defined very broadly and include not only tax deductions and credits but also decisions not to file in a particular jurisdiction, as well as the taxability of transactions. Duke Energy will implement FIN 48 effective January 1, 2007. The implementation is expected to result in a cumulative effect adjustment to beginning Retained Earnings on the Consolidated Statement of Common Stockholders' Equity and Comprehensive Income (Loss) in the first quarter 2007 in the range of $15 million to $30 million. Corresponding entries will impact a variety of balance sheet line items, including Deferred income taxes, Taxes accrued, Other Liabilities, and Goodwill. Upon implementation of FIN 48, Duke Energy will reflect interest expense related to taxes as Interest Expense, in the Consolidated Statement of Operations. In addition, subsequent accounting for FIN 48 (after January 1, 2007) will involve an evaluation to determine if any changes have occurred that would impact the existing uncertain tax positions as well as determining whether any new tax positions are uncertain. Any impacts resulting from the evaluation of existing uncertain tax positions or from the recognition of new uncertain tax positions would impact income tax expense and interest expense in the Consolidated Statement of Operations, with offsetting impacts to the balance sheet line items described above. Because of the spin-off of Spectra Energy in the first quarter of 2007, certain liabilities and deferred tax assets related to uncertain tax positions filed on Spectra Energy tax returns will be removed from Duke Energy's balance sheet. Uncertain tax positions on consolidated or combined tax returns filed by Duke Energy which are indemnified by Spectra Energy will be recorded as receivables from Spectra Energy.

FSP No. FAS 123(R)-5, "Amendment of FASB Staff Position FAS 123(R)-1" (FSP No. FAS 123(R)-5). In October 2006, the FASB staff issued FSP No. FAS 123(R)-5 to address whether a modification of an instrument in connection with an equity restructuring should be considered a modification for purposes of applying FSP No. FAS 123(R)-1, "Classification and Measurement of Freestanding Financial Instruments Originally Issued in Exchange for Employee Services under FASB Statement No. 123(R) (FSP No. FAS 123(R)-1)." In August 2005, the FASB staff issued FSP FAS 123(R)-1 to defer indefinitely the effective date of paragraphs A230–A232 of SFAS No. 123(R), and thereby require entities to apply the recognition and measurement provisions of SFAS No. 123(R) throughout the life of an instrument, unless the instrument is modified when the holder is no longer an employee. The recognition and measurement of an instrument that is modified when the holder is no longer an employee should be determined by other applicable generally accepted accounting principles. FSP No. FAS 123(R)-5 addresses modifications of stock-based awards made in connection with an equity restructuring and clarifies that for instruments that were originally issued as employee compensation and then modified, and that modification is made to the terms of the instrument solely to reflect an equity restructuring that occurs when the holders are no longer employees, no change in the recognition or the measurement (due to a change in classification) of those instruments will result if certain conditions are met. This FSP is effective for Duke Energy as of January 1, 2007. The impact to Duke Energy of applying FSP No. FAS 123(R)-5 in subsequent periods will be dependent upon the nature of any modifications to Duke Energy's share-based compensation awards.

FSP No. AUG AIR-1, "Accounting for Planned Major Maintenance Activities," (FSP No. AUG AIR-1). In September 2006, the FASB Staff issued FSP No. AUG AIR-1. This FSP prohibits the use of the accrue-in-advance method of accounting for planned major maintenance activities in annual and interim financial reporting periods, if no liability is required to be recorded for an asset retirement obligation based on a legal obligation for which the event obligating the entity has occurred. The FSP also requires disclosures regarding the method of accounting for planned major maintenance activities and the effects of implementing the FSP. The guidance in this FSP is effective for Duke Energy as of January 1, 2007 and will be applied retrospectively for all financial statements presented. Duke Energy does not anticipate the adoption of FSP No. AUG AIR-1 will have any material impact on its consolidated results of operations, cash flows or financial position.

EITF Issue No. 06-3, "How Taxes Collected from Customers and Remitted to Governmental Authorities Should Be Presented in the Income Statement (That Is, Gross versus Net Presentation)" (EITF No. 06-3). In June 2006, the EITF reached a consensus on EITF No. 06-3 to address any tax assessed by a governmental authority that is directly imposed on a revenue-producing transaction between a seller and a customer and may include, but are not limited to, sales, use, value added, and some excise taxes. For taxes within the issue's scope, the consensus requires that entities present such taxes on either a gross (i.e. included in revenues and costs) or net (i.e. exclude from revenues) basis according to their accounting policies, which should be disclosed. If such taxes are reported gross and are significant, entities should disclose the amounts of those taxes. Disclosures may be made on an aggregate basis. The consensus is effective for Duke Energy beginning January 1, 2007. Duke Energy does not anticipate the adoption of EITF No. 06-3 will have any material impact on its consolidated results of operations, cash flows or financial position.

EITF Issue No. 06-5, "Accounting for Purchases of Life Insurance—Determining the Amount That Could Be Realized in Accordance with FASB Technical Bulletin No. 85-4" (EITF No. 06-5). In June 2006, the EITF reached a consensus on the accounting for corporate-owned and bank-owned life insurance policies. EITF No. 06-5 requires that a policyholder consider the cash surrender value and any additional amounts to be received under the contractual terms of the policy in determining the amount that could be realized under the insurance contract. Amounts that are recoverable by the policyholder at the discretion of the insurance company must be excluded from the amount that could be realized. Fixed amounts that are recoverable by the policyholder in future periods in excess of one year from the surrender of the policy must be recognized at their present value. EITF No. 06-5 is effective for Duke Energy as of January 1, 2007 and must be applied as a change in accounting principle through a cumulative-effect adjustment to retained earnings or other components of equity as of January 1, 2007. Duke Energy does not anticipate the adoption of EITF No. 06-5 will have any material impact on its consolidated results of operations, cash flows or financial position.

EITF Issue No. 06-6, "Debtor's Accounting for a Modification (or Exchange) of Convertible Debt Instruments" (EITF No. 06-6). In November 2006, the EITF reached a consensus on EITF No. 06-6. EITF No. 06-6 addresses how a modification of a debt instrument (or an exchange of debt instruments) that affects the terms of an embedded conversion option should be considered in the issuer's analysis of whether debt extinguishment accounting should be applied, and further addresses the accounting for a modification of a debt instrument (or an exchange of debt instruments) that affects the terms of an embedded conversion option when extinguishment accounting is

Notes To Consolidated Financial Statements—(Continued)

not applied. EITF No. 06-6 applies to modifications (or exchanges) occurring in interim or annual reporting periods beginning after November 29, 2006, regardless of when the instrument was originally issued. Early application is permitted for modifications (or exchanges) occurring in periods for which financial statements have not been issued. There were no modifications to, or exchanges of, any of Duke Energy's debt instruments within the scope of EITF No. 06-6 in 2006. The impact to Duke Energy of applying EITF No. 06-6 in subsequent periods will be dependent upon the nature of any modifications to, or exchanges of, any debt instruments within the scope of EITF No. 06-6. Refer to Note 15.

2. Acquisitions and Dispositions

Acquisitions. Duke Energy consolidates assets and liabilities from acquisitions as of the purchase date, and includes earnings from acquisitions in consolidated earnings after the purchase date. Assets acquired and liabilities assumed are recorded at estimated fair values on the date of acquisition. The purchase price minus the estimated fair value of the acquired assets and liabilities meeting the definition of a business as defined in EITF Issue No. 98-3, "Determining Whether a Nonmonetary Transaction Involves Receipt of Productive Assets or of a Business" (EITF 98-3), is recorded as goodwill. The allocation of the purchase price may be adjusted if additional, requested information is received during the allocation period, which generally does not exceed one year from the consummation date; however, it may be longer for certain income tax items.

Cinergy Merger. On April 3, 2006, the previously announced merger between Duke Energy and Cinergy was consummated (see Note 1 for additional information). For accounting purposes, the effective date of the merger was April 1, 2006. The merger combines the Duke Energy and Cinergy regulated franchises as well as deregulated generation in the Midwestern United States. The merger provides more regulatory, geographic and weather diversity to Duke Energy's earnings. See Note 4 for discussion of regulatory impacts of the merger.

The merger has been accounted for under the purchase method of accounting with Duke Energy treated as the acquirer for accounting purposes. As a result, the assets and liabilities of Cinergy were recorded at their respective fair values as of April 3, 2006 and the results of Cinergy's operations are included in the Duke Energy consolidated financial statements beginning as of the effective date of the merger. Except for an adjustment related to pension and other postretirement benefit obligations, as mandated by SFAS No. 87, "Employers' Accounting for Pensions" (SFAS No. 87) and SFAS No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions," (SFAS No. 106), the accompanying consolidated financial statements do not reflect any pro forma adjustments related to Cinergy's regulated operations that are accounted for pursuant to SFAS No. 71, which are comprised of the regulated transmission and distribution operations of Duke Energy Ohio, Inc. (Duke Energy Ohio) (formerly The Cincinnati Gas & Electric Company's regulated transmission and distribution), Duke Energy Indiana, Inc. (Duke Energy Indiana) (formerly PSI Energy, Inc.) and Duke Energy Kentucky, Inc. (Duke Energy Kentucky) (formerly The Union Light, Heat and Power Company). Under the rate setting and recovery provisions currently in place for these regulated operations which provide revenues derived from cost, the fair values of the individual tangible and intangible assets and liabilities are considered to approximate their carrying values.

The fair values used for recording the assets acquired and liabilities assumed are based on valuation analyses.

In connection with the merger, Duke Energy issued 1.56 shares of Duke Energy common stock for each outstanding share of Cinergy common stock, which resulted in the issuance of approximately 313 million shares of Duke Energy common stock. Based on the market price of Duke Energy common stock during the period including the two trading days before through the two trading days after May 9, 2005, the date Duke Energy and Cinergy announced the merger, the transaction is valued at approximately $9.1 billion and has resulted in incremental goodwill to Duke Energy of approximately $4.5 billion. The amount of goodwill results from significant strategic and financial benefits of the merger including:

- increased financial strength and flexibility;
- stronger utility business platform;
- greater scale and fuel diversity, as well as improved operational efficiencies for the merchant generation business;
- broadened electric distribution platform;
- improved reliability and customer service through the sharing of best practices;
- increased scale and scope of the electric and gas businesses with stand-alone strength;
- complementary positions in the Midwest;

- greater customer diversity;
- combined expertise; and
- significant cost savings synergies.

The following table summarizes the estimated fair values of the assets acquired and liabilities assumed at the date of acquisition:

Purchase Price Allocation

	April 3, 2006
	(in millions)
Purchase price	$ 9,115
Current assets	2,670
Investments and other assets	1,499
Property, plant and equipment[(a)]	10,595
Intangible assets	1,091
Regulatory assets and deferred debits	1,449
Total assets acquired	17,304
Current liabilities	4,137
Long-term debt	4,295
Deferred credits and other liabilities	4,266
Minority Interests	11
Net identifiable assets acquired	4,595
Goodwill	$ 4,520

(a) Amounts recorded for regulated property, plant and equipment by Duke Energy on the acquisition date are net of approximately $3,995 million of accumulated depreciation of acquired assets.

Goodwill recorded as of December 31, 2006 resulting from Duke Energy's merger with Cinergy is $4,385 million, none of which is deductible for income tax purposes. Approximately $135 million of goodwill was allocated to Cinergy Marketing and Trading, LP, and Cinergy Canada, Inc. (collectively CMT) (see Note 13), which was sold in October 2006. As of December 31, 2006, the allocation of the remaining goodwill to the reporting units was substantially complete, with approximately $3,500 million and $885 million being allocated to the U.S. Franchised Electric and Gas and Commercial Power segments, respectively (see Note 10).

The following unaudited consolidated pro forma financial results are presented as if the Cinergy merger had occurred at the beginning of each of the periods presented:

Unaudited Consolidated Pro Forma Results

	Year Ended December 31,	
	2006	2005
	(In millions, except per share amounts)	
Operating revenues	$16,776	$21,413
Income from continuing operations	2,009	2,897
Net income	1,854	2,230
Earnings available for common stockholders	1,854	2,218
Earnings per share (from continuing operations)		
Basic	$ 1.61	$ 2.32
Diluted	$ 1.58	$ 2.26
Earnings per share		
Basic	$ 1.48	$ 1.78

Diluted	$ 1 46	$ 1.73

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

Pro forma results for the year ended December 31, 2006 include approximately $128 million of charges related to costs to achieve the merger and related synergies, which are recorded within Operating Expenses on the Consolidated Statements of Operations. Pro forma results for the years ended December 31, 2006 and 2005 do not reflect the pro forma effects of any significant transactions completed by Duke Energy other than the merger with Cinergy. The pre-tax impacts of purchase accounting on the 2006 results of operations of Duke Energy were charges of approximately $98 million.

Other Acquisitions. During the first quarter of 2006, International Energy closed on two transactions which resulted in the acquisition of an additional 27% interest in the Aguaytia Integrated Energy Project (Aguaytia), located in Peru, for approximately $31 million (approximately $18 million net of cash acquired). The project's scope includes the production and processing of natural gas, sale of liquefied petroleum gas (LPG) and NGLs and the generation, transmission and sale of electricity from a 177 megawatt power plant. These acquisitions increased International Energy's ownership in Aguaytia to 66% and resulted in Duke Energy accounting for Aguaytia as a consolidated entity. Prior to the acquisition of this additional interest, Aguaytia was accounted for as an equity method investment. No goodwill was recorded as a result of this acquisition.

During the first quarter of 2006, Duke Energy acquired the remaining 33 1/3% interest in Bridgeport Energy LLC (Bridgeport) from United Bridgeport Energy LLC (UBE) for approximately $71 million. No goodwill was recorded as a result of this acquisition. The assets and liabilities of Bridgeport were included as part of DENA's power generation assets which were sold to a subsidiary of LS Power Equity Partners (LS Power) (see Note 13).

In May 2006, Duke Energy announced an agreement to acquire an 825 megawatt power plant located in Rockingham County, North Carolina, from Dynegy for approximately $195 million. The Rockingham plant is a peaking power plant used during times of high electricity demand, generally in the winter and summer months and consists of five 165 megawatt combustion turbine units capable of using either natural gas or oil to operate. The acquisition is consistent with Duke Energy's plan to meet customers' electric needs for the foreseeable future. The transaction, which closed in the fourth quarter of 2006, required approvals by the North Carolina Utilities Commission (NCUC) and the Federal Energy Regulatory Commission (FERC). The NCUC approved it on July 25, 2006 and the FERC issued an order authorizing the transaction on October 31, 2006. In addition, the U.S. Federal Trade Commission (FTC) approved the transaction on July 20, 2006, under the Hart-Scott-Rodino Antitrust Improvement Act. No goodwill was recorded as a result of this acquisition.

In August 2005, Natural Gas Transmission acquired natural gas storage and pipeline assets in Southwest Virginia and an additional 50% interest in Saltville Gas Storage LLC (Saltville Storage) from units of AGL Resources for approximately $62 million. This transaction increased Natural Gas Transmission's ownership percentage of Saltville Storage to 100%. No goodwill was recorded as a result of this acquisition.

In August 2005, Natural Gas Transmission acquired the Empress System natural gas processing and NGL marketing business from ConocoPhillips for approximately $230 million as part of the Field Services ConocoPhillips transaction discussed further in the Dispositions section below. No goodwill was recorded as a result of this acquisition.

In the second quarter of 2004, Field Services acquired gathering, processing and transmission assets in southeast New Mexico from ConocoPhillips for a total purchase price of approximately $80 million, consisting of $74 million in cash and the assumption of approximately $6 million of liabilities. As the acquired assets were not considered businesses under the guidance in EITF 98-3, no goodwill was recognized in connection with this transaction.

In the third quarter of 2004, Field Services acquired additional interest in three separate entities (for which DEFS owned less than 100%, but had been consolidating) for a total purchase price of $4 million, and the exchange of some Field Services' assets. Two of these acquisitions, Mobile Bay Processing Partners (MBPP) and Gulf Coast NGL Pipeline, LLC (GC), resulted in 100% ownership by Field Services. The MBPP transaction involved MBPP transferring certain long-lived assets to El Paso Corporation for El Paso Corporation's interest in MBPP. As a result of this non-monetary transaction, the assets transferred were written-down to their estimated fair value which resulted in Duke Energy recognizing a pre-tax impairment of approximately $13 million, which was approximately $4 million net of minority interest. An additional 12% interest in Dauphin Island Gathering Partners (DIGP) was also purchased for $2 million, which resulted in 84% ownership by Field Services. MBPP owns processing assets in the Onshore Gulf of Mexico. GC owns a 16.67% interest in two equity investments. DIGP owns gathering and transmission assets in the Offshore Gulf of Mexico.

The pro forma results of operations for Duke Energy as if those acquisitions (other than the Cinergy merger) which closed prior to December 31, 2006 occurred as of the beginning of the periods presented do not materially differ from reported results.

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

Dispositions. In December 2006, Duke Energy Indiana agreed to sell one unit of its Wabash River Power Station (Unit 1) to the Wabash Valley Power Association. The price of the transaction will be based on the book value of Unit 1 at the time of closing, which is currently estimated to be approximately $110-$120 million. The sale must be approved by the Indiana Utility Regulatory Commission (IURC), the FERC, the FTC and the Department of Justice (DOJ). These approvals are anticipated by mid-2007. Duke Energy does not anticipate recognizing a material gain or loss on this transaction.

On January 12, 2007, Duke Energy Indiana filed a petition with the IURC requesting authority to sell Wabash River Unit #1 to the Wabash Valley Power Association, Inc. pursuant to an Asset Purchase Agreement along with approval of the Operation and Maintenance Agreement and the Common Facilities Agreement associated with the sale. Wabash River Unit #1 will be replaced by the Wheatland facility which was purchased by Duke Energy Indiana in 2005. Duke Energy Indiana is also requesting approval of the accounting and ratemaking treatment of the sale to reflect the difference in costs of the two facilities.

For the year ended December 31, 2006, the sale of other assets and businesses resulted in approximately $2 billion in proceeds and net pre-tax gains of $276 million recorded in Gains (Losses) on Sales of Other Assets and Other, net on the Consolidated Statements of Operations. These sales exclude assets that were held for sale and reflected in discontinued operations, both of which are discussed in Note 13, and sales by Crescent prior to deconsolidation which are discussed separately below. Significant sales of other assets during 2006 are detailed as follows:

- On September 7, 2006, an indirect wholly owned subsidiary of Duke Energy closed an agreement to create a joint venture of Crescent (the Crescent JV) with Morgan Stanley Real Estate Fund V U.S., L.P. (MSREF) and other affiliated funds controlled by Morgan Stanley (collectively the "MS Members"). Under the agreement, the Duke Energy subsidiary contributed all of the membership interests in Crescent to a newly-formed joint venture, which was ascribed an enterprise value of approximately $2.1 billion as of December 31, 2005. In conjunction with the formation of the Crescent JV, the joint venture, Crescent and Crescent's subsidiaries entered into a credit agreement with third party lenders under which Crescent borrowed approximately $1.21 billion, net of transaction costs, of which approximately $1.19 billion was immediately distributed to Duke Energy. Immediately following the debt transaction, the MS Members collectively acquired a 49% membership interest in the Crescent JV from Duke Energy for a purchase price of approximately $415 million. A 2% interest in the Crescent JV was also issued by the joint venture to the President and Chief Executive Officer of Crescent which is subject to forfeiture if the executive voluntarily leaves the employment of the Crescent JV within a three year period. Additionally, this 2% interest can be put back to the Crescent JV after three years or possibly earlier upon the occurrence of certain events at an amount equal to 2% of the fair value of the Crescent JV's equity as of the put date. Therefore, the Crescent JV will accrue the obligation related to the put as a liability over the three year forfeiture period. Accordingly, Duke Energy has an effective 50% ownership in the equity of Crescent JV for financial reporting purposes. In conjunction with this transaction, Duke Energy recognized a pre-tax gain on the sale of approximately $250 million which has been classified as a component of Gains (Losses) on Sales of Other Assets and Other, net in the accompanying Consolidated Statement of Operations for the year ended December 31, 2006. As a result of the Crescent transaction, Duke Energy no longer controls the Crescent JV and on September 7, 2006 deconsolidated its investment in Crescent and subsequently will account for its investment in the Crescent JV utilizing the equity method of accounting. Duke Energy's equity investment in the Crescent JV is approximately $180 million as of December 31, 2006. The proceeds from the sale were recorded on the Consolidated Statements of Cash Flows as follows: approximately $1.2 billion in long-term debt proceeds, net of issuance costs, were classified as Proceeds from the issuance of long-term debt within Financing Activities, and approximately $380 million, which represents cash received from the MS Members net of cash held by Crescent as of the transaction date, were classified as Net proceeds from the sales of and distributions from equity investments and other assets, and sales of and collections on notes receivable within Investing Activities.
- Natural Gas Transmission's sale of certain Stone Mountain natural gas gathering system assets resulted in proceeds of $18 million (which is reflected in Net proceeds from the sales of equity investments and other assets, and sales of and collections on notes receivable within Cash Flows from Investing Activities in the Consolidated Statements of Cash Flows), and pre-tax gain of $5 million which was recorded in Gains (Losses) on Sales of Other Assets and Other, net in the accompanying Consolidated Statements of Operations. In addition, Natural Gas Transmission's sale of stock, received as consideration for the settlement of a customers' transportation contract, resulted in proceeds of approximately $29 million (which is reflected in Other, assets within Cash Flows from Operating Activities in the Consolidated Statements of Cash Flows) and a pre-tax gain of $29 million, of which

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

approximately $28 million was recorded in Gains (Losses) on Sales of Other Assets and Other, net and approximately $1 million was recorded in Other Income and Expenses, net in the accompanying Consolidated Statements of Operations (see Note 9).

- Commercial Power's sale of emission allowances, which resulted in proceeds of $136 million and pre-tax losses on sales of approximately $29 million (see Note 10), which was recorded in Gains (Losses) on Sales of Other Assets and Other, net, in the Consolidated Statements of Operations. This was partially offset by the sale of the Pine Mountain synthetic fuel facility, which resulted in proceeds of approximately $8 million and a pre-tax gain of approximately $6 million, which was recorded in Gains (Losses) on Sales of Other Assets and Other, net, in the Consolidated Statements of Operations.

- As a result of a settlement of a property insurance claim, Natural Gas Transmission received proceeds of approximately $30 million and recognized a pre-tax gain of approximately $10 million, which was recorded in Gains (Losses) on Sales of Other Assets and Other, net, in the Consolidated Statements of Operations.

For the period from January 1, 2006 to September 7, 2006, Crescent commercial and multi-family real estate sales resulted in $254 million of proceeds and $201 million of net pre-tax gains recorded in Gains on Sales of Investments in Commercial and Multi-Family Real Estate on the Consolidated Statements of Operations. Sales primarily consisted of two office buildings at Potomac Yard in Washington, D.C. for a pre-tax gain of $81 million and land at Lake Keowee in northwestern South Carolina for a pre-tax gain of $52 million, as well as several other large land tract sales.

For the year ended December 31, 2005, the sale of other assets, businesses and equity investments resulted in approximately $2.3 billion in proceeds, pre-tax gains of $534 million recorded in Gains (Losses) on Sales of Other Assets and Other, net, on the accompanying Consolidated Statements of Operations and pre-tax gains of $1,225 million recorded in Gains (Losses) on Sales and Impairments of Equity Method Investments on the accompanying Consolidated Statements of Operations. These sales exclude assets that were held for sale and reflected in discontinued operations, both of which are discussed in Note 13, and commercial and multi-family real estate sales by Crescent which are discussed separately below. Significant sales of other assets and equity investments during 2005 are detailed as follows:

- In February 2005, DEFS sold its wholly owned subsidiary Texas Eastern Products Pipeline Company, LLC (TEPPCO GP), which is the general partner of TEPPCO Partners, LP (TEPPCO LP), for approximately $1.1 billion and Duke Energy sold its limited partner interest in TEPPCO LP for approximately $100 million, in each case to Enterprise GP Holdings LP (EPCO), an unrelated third party. These transactions resulted in pre-tax gains of $1.2 billion, which were recorded in Gains (Losses) on Sales and Impairments of Equity Method Investments in the Consolidated Statements of Operations. Minority Interest Expense of $343 million was recorded in the accompanying Consolidated Statements of Operations to reflect ConocoPhillips' proportionate share in the pre-tax gain on sale of TEPPCO GP. Additionally, in July 2005, Duke Energy completed the agreement with ConocoPhillips, Duke Energy's co-equity owner in DEFS, to reduce Duke Energy's ownership interest in DEFS from 69.7% to 50% (the DEFS disposition transaction), which results in Duke Energy and ConocoPhillips becoming equal 50% owners in DEFS. Duke Energy has received, directly and indirectly through its ownership interest in DEFS, a total of approximately $1.1 billion from ConocoPhillips and DEFS, consisting of approximately $1.0 billion in cash and approximately $0.1 billion of assets. The DEFS disposition transaction resulted in a pre-tax gain of approximately $575 million, which was recorded in Gains (Losses) on Sales of Other Assets and Other, net, in the accompanying Consolidated Statements of Operations. The DEFS disposition transaction includes the transfer to Duke Energy of DEFS' Canadian natural gas gathering and processing facilities. Additionally, the DEFS disposition transaction included the acquisition of ConocoPhillips' interest in the Empress System. Subsequent to the closing of the DEFS disposition transaction, effective on July 1, 2005, DEFS is no longer consolidated into Duke Energy's consolidated financial statements and is accounted for by Duke Energy as an equity method investment. See Note 8 for the impacts of this transaction on certain cash flow hedges. The Canadian natural gas gathering and processing facilities and the Empress System are included in the Natural Gas Transmission segment.

- In December 2005, the Duke Energy Income Fund (Income Fund), a Canadian income trust fund, was created to acquire all of the common shares of Duke Energy Midstream Services Canada Corporation (Duke Midstream) from a subsidiary of Duke Energy. The Income Fund sold an approximate 40% ownership interest in Duke Midstream for approximately $110 million, which was included in Proceeds from Duke Energy Income Fund within Cash Flows from Financing activities on the Consolidated Statements of Cash Flows. In January 2006, a subsequent greenshoe sale of additional ownership interests, pursuant to an overallotment option, in the Income Fund were sold for approximately $10 million. Duke Energy retains an ownership interest in the Income Fund of approximately 58% and will continue to operate and manage this business. Duke Energy continues to consolidate the results of this business.

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

- In December 2005, Commercial Power recorded a $75 million charge related to the termination of structured power contracts in the Southeast, which was recorded in Gains (Losses) on Sales of Other Assets and Other, net on the accompanying Consolidated Statements of Operations.

For the year ended December 31, 2005, Crescent's commercial and multi-family real estate sales resulted in $372 million of proceeds and $191 million of net pre-tax gains recorded in Gains on Sales of Investments in Commercial and Multi-Family Real Estate on the Consolidated Statements of Operations. Sales included a large land sale in Lancaster County, South Carolina that resulted in $42 million of pre-tax gains, and several other "legacy" land sales. Additionally, Crescent had $45 million in pre-tax income related to a distribution from an interest in a portfolio of commercial office buildings which was recognized in Other Income and Expenses, net, in the accompanying Consolidated Statements of Operations (see Note 24).

For the year ended December 31, 2004, the sale of other assets and businesses (which excludes assets held for sale as of December 31, 2004 and discontinued operations, both of which are discussed in Note 13, and sales by Crescent which are discussed separately below) resulted in approximately $715 million in cash proceeds plus a $48 million note receivable from the buyers, and net pre-tax losses of $416 million recorded in Gains (Losses) on Sales of Other Assets and Other, net and pre-tax losses of $4 million recorded in (Losses) Gains on Sales and Impairments of Equity Method Investments on the Consolidated Statements of Operations. (Losses) Gains on Sales and Impairments of Equity Method Investments included a $23 million impairment charge, which is discussed in Note 12. Significant sales of other assets in 2004 are detailed as follows:

- Natural Gas Transmission's asset sales totaled $25 million in net proceeds. Those sales resulted in total pre-tax gains of approximately $33 million, of which $17 million was recorded in Gains (Losses) on Sales of Other Assets and Other, net and $16 million was recorded in Gains (Losses) on Sales and Impairments of Equity Method Investments in the Consolidated Statements of Operations. Significant sales included the sale of storage gas related to the Canadian distribution operations, the sale of Natural Gas Transmission's interest in the Millennium Pipeline, and the sale of land.

- Field Services asset sales totaled $13 million in net proceeds. Those sales resulted in gains of $2 million which were recorded in Gains (Losses) on Sales of Other Assets and Other, net in the Consolidated Statements of Operations. These sales consisted of multiple small sales.

- Commercial Power's asset sales totaled approximately $464 million in net proceeds and a $48 million note receivable. Those sales resulted in pre-tax losses of $360 million which were recorded in Gains (Losses) on Sales of Other Assets and Other, net in the Consolidated Statements of Operations. Significant sales included:

- Commercial Power's eight natural gas-fired merchant power plants in the Southeastern United States: Hot Spring (Arkansas); Murray and Sandersville (Georgia); Marshall (Kentucky); Hinds, Southaven, Enterprise and New Albany (Mississippi); and certain other power and gas contracts (collectively, the Southeast Plants). Duke Energy decided to sell the Southeast Plants in 2003, and recorded an impairment charge of $1.3 billion in 2003 since the assets' carrying values exceeded their estimated fair values. The sale of those assets to KGen Partners LLC (KGen) obtained all required regulatory approvals and consents and closed on August 5, 2004. This transaction resulted in a pre-tax loss of approximately $360 million recorded in Gains (Losses) on Sales of Other Assets and Other, net in the 2004 Consolidated Statement of Operations. Nearly all of the loss was recognized in the first quarter of 2004 to reduce the assets' carrying values to their estimated fair values, and approximately $4 million of the loss was recognized in the third quarter of 2004 upon closing. The fair value of the plants used for recording the loss in the first quarter was based on the sales price of approximately $475 million, as announced on May 4, 2004. The actual sales price consisted of $420 million of cash and a $48 million note receivable from KGen, which bears variable interest at the London Interbank Offered Rate (LIBOR) plus 13.625% per annum, compounded quarterly. The note is secured by a fourth lien on (i) substantially all of KGen's assets and (ii) stock of KGen LLC (KGen's owner), each subject to certain permitted liens and a first lien on cash in certain KGen accounts. The note was repaid in full during 2005.

Duke Energy retained certain guarantees related to the sold assets. In conjunction with the sale, Duke Energy arranged a letter of credit with a face amount of $120 million in favor of Georgia Power Company, to secure obligations of a KGen subsidiary under a seven-year power sales agreement, commencing in May 2005, under which KGen will provide power from one of the plants to Georgia Power. Duke Energy is the ultimate obligor to the letter of credit provider, but KGen has an obligation to reimburse Duke Energy for any payments made by it under the letter of credit, as well as expenses incurred by Duke Energy in connection with the letter of credit. In February 2007, this guarantee was cancelled (see Note 18). Duke Energy will continue to provide services

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

under a long-term operating agreement for one of the plants. As a result of Duke Energy's significant continuing involvement in the operations of the plants, this transaction did not qualify for discontinued operations presentation, as prescribed by SFAS No. 144. However, this continuing involvement did not prohibit sale accounting under SFAS No. 66, "Accounting for Sales of Real Estate."

- During 2004, a 25% undivided interest in Commercial Power's Vermillion facility was sold for proceeds of approximately $44 million. This sale was anticipated in 2003 and, therefore, an $18 million loss on sale was recorded during 2003.
- International Energy completed the sale of its 30% equity interest in Compañia de Nitrógeno de Cantarell, S.A. de C.V. (Cantarell) a nitrogen production and delivery facility in the Bay of Campeche, Gulf of Mexico on September 8, 2004. The sale resulted in $60 million in net proceeds and an approximate $2 million pre-tax gain recorded to Gains (Losses) on Sales and Impairments of Equity Method Investments on the Consolidated Statements of Operations. A $13 million non-cash charge to Operation, Maintenance and Other expenses on the Consolidated Statements of Operations, related to a note receivable from Cantarell, was recorded in the first quarter of 2004.
- Additional asset and business sales in 2004 totaled $222 million in net proceeds. Those sales resulted in net pre-tax losses of $74 million, of which $75 million was recorded in Gains (Losses) on Sales of Other Assets, net and a $1 million gain was recorded in Gains (Losses) on Sales and Impairments of Equity Method Investments in the Consolidated Statements of Operations. These sales primarily related to some contracts at Duke Energy Trading and Marketing, LLC (DETM). DETM held a net liability position in certain contracts and, as part of the sale, DETM paid a third party net cash payments of $99 million related to the sale of these assets which are included in Cash Flows from Operating Activities. This resulted in a net loss of $65 million recorded in Gains (Losses) on Sales of Other Assets and Other, net in the 2004 Consolidated Statement of Operations. Other significant sales included Duke Energy Royal LLC's interest in six energy service agreements and DukeSolutions Huntington Beach, LLC.

For the year ended December 31, 2004, Crescent's commercial and multi-family real estate sales resulted in $606 million of proceeds, and $192 million of net gains recorded in Gains on Sales of Investments in Commercial and Multi-Family Real Estate on the Consolidated Statements of Operations. Significant sales included commercial project sales, resulting primarily from the sale of a commercial project in the Washington, D.C. area in March; real estate sales due primarily to the sale of the Alexandria and Arlington land tracts in the Washington, D.C. area; and several large land tract sales.

3. Business Segments

In conjunction with Duke Energy's merger with Cinergy, effective with the second quarter of 2006, Duke Energy adopted new business segments that management believes properly align the various operations of Duke Energy with how the chief operating decision maker views the business. Duke Energy operates the following business units: U.S. Franchised Electric and Gas, Natural Gas Transmission, Field Services, Commercial Power, International Energy and Crescent. Prior to Duke Energy's sale of an effective 50% ownership interest in Crescent in September 2006 (see below), this segment represented Duke Energy's 100% ownership of Crescent Resources, LLC. Duke Energy's chief operating decision maker regularly reviews financial information about each of these business units in deciding how to allocate resources and evaluate performance. All of the Duke Energy business units are considered reportable segments under SFAS No. 131. Prior to the September 2005 announcement of the exiting of the majority of former DENA's businesses (see below), former DENA's operations were considered a separate reportable segment. The term DENA, as used throughout the Notes to Consolidated Financial Statements, refers to the former merchant generation operations in the Western and Eastern U.S., as well as operations in the Midwest and Southeast. Under Duke Energy's new segment structure, the merchant generation operations of the Midwest and Southeast are presented in continuing operations as a component of the Commercial Power segment for all periods presented and the Western and Eastern operations are presented as a component of discontinued operations within Other for all periods presented. Prior to the change in business segments, former DENA's continuing operations, which primarily include the merchant generation operations in the Midwest and Southeast, were included in Other in 2005 and as a component of the DENA segment in all prior periods, and discontinued operations were included in the former DENA segment for all periods. There is no aggregation within Duke Energy's defined business segments.

U.S. Franchised Electric and Gas generates, transmits, distributes and sells electricity in central and western North Carolina, western South Carolina, southwestern Ohio, central and southern Indiana, and northern Kentucky. U.S. Franchised Electric and Gas also transports and sells natural gas in southwestern Ohio and northern Kentucky. It conducts operations primarily through Duke Energy Carolinas, Duke

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

Energy Ohio, Duke Energy Indiana and Duke Energy Kentucky. These electric and gas operations are subject to the rules and regulations of the FERC, the NCUC, the Public Service Commission of South Carolina (PSCSC), the Public Utilities Commission of Ohio (PUCO), the IURC and the Kentucky Public Service Commission (KPSC).

Cinergy, a Delaware corporation organized in 1993, owns all outstanding common stock of its public utility companies. Duke Energy Ohio and Duke Energy Indiana, as well as other businesses including (a) cogeneration and energy efficiency investments and (b) natural gas and power marketing and trading operations, conducted primarily through CMT, which was sold to Fortis in October 2006 (see Note 13).

Duke Energy Ohio, an Ohio corporation organized in 1837, is a combination electric and gas public utility company that provides service in the southwestern portion of Ohio and, through its wholly-owned subsidiary Duke Energy Kentucky, in nearby areas of Kentucky. Its principal lines of business include generation, transmission, and distribution of electricity, the sale of and/or transportation of natural gas, and power marketing and trading. The regulated operations of Duke Energy Ohio are included in the U.S. Franchised Electric and Gas segment, whereas the unregulated portion of the business is included in the Commercial Power segment.

Duke Energy Indiana, an Indiana corporation organized in 1942, is a vertically integrated and regulated electric utility that provides service in central and southern Indiana. Its primary line of business is generation, transmission, and distribution of electricity.

Natural Gas Transmission provides transportation and storage of natural gas for customers along the U.S. East Coast, the Southeast, and in Canada. Natural Gas Transmission also provides natural gas sales and distribution service to retail customers in Ontario, natural gas processing services to customers in Western Canada and other energy related services. Natural Gas Transmission does business primarily through Duke Energy Gas Transmission, LLC. Duke Energy Gas Transmission, LLC's natural gas transmission and storage operations in the U.S. are primarily subject to the FERC's and the U.S. Department of Transportation's rules and regulations, while natural gas gathering, processing, transmission, distribution and storage operations in Canada are primarily subject to the rules and regulations of the National Energy Board (NEB) and the Ontario Energy Board (OEB). Natural Gas Transmission also includes the results of operations of the McMahon facility and the Canadian gathering and processing facilities transferred to Natural Gas Transmission from DENA and Field Services, respectively, during 2005.

Field Services gathers, compresses, processes, transports, trades and markets, and stores natural gas; and fractionates, transports, gathers, treats, processes, trades and markets, and stores NGLs. It conducts operations primarily through DEFS, which is owned 50 percent by ConocoPhillips and 50 percent by Duke Energy. Field Services gathers raw natural gas through gathering systems located in seven major natural gas producing regions: Permian, Mid-Continent, East Texas-North Louisiana, South, Central, Rocky Mountain and Gulf Coast.

In February 2005, DEFS sold its wholly owned subsidiary TEPPCO GP, which is the general partner of TEPPCO LP, and Duke Energy sold its limited partner interest in TEPPCO LP, in each case to EPCO, an unrelated third party. As a result of the DEFS disposition transaction discussed in Note 2, Duke Energy deconsolidated its investment in DEFS effective July 1, 2005 and subsequently has accounted for it as an investment utilizing the equity method of accounting. In connection with the DEFS disposition transaction, DEFS transferred its Canadian natural gas gathering and processing facilities to Duke Energy's Natural Gas Transmission segment.

See Note 25 for the impacts on Duke Energy's business segments of the spin-off of Duke Energy's natural gas transmission businesses to Spectra Energy effective January 2, 2007.

Commercial Power owns, operates and manages non-regulated merchant power plants and engages in the wholesale marketing and procurement of electric power, fuel and emission allowances related to these plants as well as other contractual positions. Commercial Power also develops and implements customized energy solutions. Commercial Power's generation asset fleet consists of Duke Energy Ohio's non-regulated generation in Ohio and the five Midwestern gas-fired merchant generation assets that were a portion of former DENA. Commercial Power's assets comprise approximately 8,100 megawatts (MW) of power generation primarily located in the Midwestern United States. The asset portfolio has a diversified fuel mix with base-load and mid-merit coal-fired units as well as combined cycle and peaking natural gas-fired units. Most of the generation asset output in Ohio has been contracted through the Rate Stabilization Plan (RSP).

International Energy operates and manages power generation facilities, and engages in sales and marketing of electric power and natural gas outside the U.S. and Canada. It conducts operations primarily through Duke Energy International, LLC (DEI) and its activities target power generation in Latin America. Additionally, International Energy owns equity investments in National Methanol Company (NMC), located in Saudi Arabia, which is a leading regional producer of methanol and methyl tertiary butyl ether (MTBE), Compania de Servicios de Compression de Campeche, S.A. (Campeche), located in the Cantarell oil field in the Bay of Campeche, Mexico, which compresses and dehydrates natural gas and extracts NGLs, and Attiki Gas Supply S.A. (Attiki), located in Athens, Greece, which is a natural gas distributor.

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

Crescent develops and manages high-quality commercial, residential and multi-family real estate projects primarily in the Southeastern and Southwestern United States. Some of these projects are developed and managed through joint ventures. Crescent also manages "legacy" land holdings in North and South Carolina. On September 7, 2006, Duke Energy deconsolidated Crescent due to a reduction in ownership and its inability to exercise control over Crescent (see Note 2). Crescent has been accounted for as an equity method investment since the date of deconsolidation.

The remainder of Duke Energy's operations is presented as "Other". While it is not considered a business segment, Other primarily includes the following:

- The remaining portion of Duke Energy's business formerly known as DENA, including its 100% owned affiliates Duke Energy Marketing America, LLC and Duke Energy Marketing Canada Corp. Duke Energy also participates in DETM. DETM is 40% owned by ExxonMobil Corporation and 60% owned by Duke Energy. During the third quarter of 2005, Duke Energy's Board of Directors authorized and directed management to execute the sale or disposition of substantially all of former DENA's remaining assets and contracts outside the Midwestern United States and certain contractual positions related to the Midwestern assets. The exit plan was completed in the second quarter of 2006 (see Note 13). In addition, management will continue to wind down the limited remaining operations of DETM. As a result of this exit plan, the results of operations for most of former DENA's businesses which Duke Energy has exited have been reflected as discontinued operations in the accompanying Consolidated Statements of Operations for all years presented. Continuing operations related to the former DENA operations within Other consist primarily of DETM, which management continues to wind down.

- Other also includes certain unallocated corporate costs, certain discontinued hedges, DukeNet Communications, LLC (DukeNet), Bison Insurance Company Limited (Bison), Duke Energy's wholly owned, captive insurance subsidiary, Cinergy's equity financing business and Duke Energy's 50% interest in Duke/Fluor Daniel (D/FD). DukeNet develops, owns and operates a fiber optic communications network, primarily in the Carolinas, serving wireless, local and long-distance communications companies, internet service providers and other businesses and organizations. During 2003, Duke Energy determined that it would exit the refined products business at Duke Energy Merchants, LLC (DEM) in an orderly manner, and continues to unwind its portfolio of contracts. As of December 31, 2006, DEM had completed the exit of its business, and all of the results of operations have been classified as discontinued operations in the accompanying Consolidated Statements of Operations for all periods presented. Bison's principal activities, as a captive insurance entity, include the insurance and reinsurance of various business risks and losses, such as workers compensation, property, business interruption and general liability of subsidiaries and affiliates of Duke Energy. Bison also participates in reinsurance activities with certain third parties, on a limited basis. Cinergy has a business which invests in start up businesses utilizing new energy technologies as well as technologies utilizing energy infrastructure, such as broadband over power line services. D/FD is a 50/50 partnership between subsidiaries of Duke Energy and Fluor Corporation (Fluor). During 2003, Duke Energy and Fluor announced that they would dissolve D/FD and adopted a plan for an orderly wind-down of the D/FD business. The wind-down has been substantially completed as of December 31, 2006. Previously, D/FD provided comprehensive engineering, procurement, construction, commissioning and operating plant services for fossil-fueled electric power generating facilities worldwide.

- During 2003, Duke Energy decided to exit the merchant finance business conducted by Duke Capital Partners, LLC (DCP). DCP had been previously included in Other. As of December 31, 2005, Duke Energy had exited the merchant finance business, and all of the results of operations for DCP have been classified as discontinued operations in the accompanying Consolidated Statements of Operations.

- During the first quarter of 2005, Duke Energy discontinued hedge accounting for certain contracts related to Field Services' commodity price risk and changes in the fair value of these contracts subsequent to hedge discontinuance have been classified in Other. See Note 8 for further discussion.

Duke Energy's reportable segments offer different products and services and are managed separately as business units. Accounting policies for Duke Energy's segments are the same as those described in Note 1. Management evaluates segment performance based on earnings before interest and taxes from continuing operations, after deducting minority interest expense related to those profits (EBIT).

On a segment basis, EBIT excludes discontinued operations, represents all profits from continuing operations (both operating and non-operating) before deducting interest and taxes, and is net of the minority interest expense related to those profits. Cash, cash equivalents and short-term investments are managed centrally by Duke Energy, so the associated realized and unrealized gains and losses from foreign currency transactions and interest and dividend income on those balances are excluded from the segments' EBIT.

Notes To Consolidated Financial Statements—(Continued)

Transactions between reportable segments are accounted for on the same basis as revenues and expenses in the accompanying Consolidated Financial Statements.

Business Segment Data[a]

	Unaffiliated Revenues	Intersegment Revenues	Total Revenues	Segment EBIT/ Consolidated Earnings from Continuing Operations before Income Taxes	Depreciation and Amortization	Capital and Investment Expenditures	Segment Assets[b]
				(in millions)			
Year Ended December 31, 2006							
U.S. Franchised Electric and Gas	$ 8,077	$ 21	$ 8,098	$ 1,811	$ 1,280	$ 2,381	$ 34,346
Natural Gas Transmission	4,515	8	4,523	1,438	480	790	19,002
Field Services[f]	—	—	—	569	—	—	1,233
Commercial Power[e]	1,396	6	1,402	21	160	209	6,826
International Energy	961	—	961	139	77	58	3,332
Crescent[c][g]	221	—	221	532	1	507	180
Total reportable segments	15,170	35	15,205	4,510	1,998	3,945	64,919
Other[e]	14	128	142	(581)	51	131	3,810
Eliminations and reclassifications	—	(163)	(163)	—	—	—	(29)
Interest expense	—	—	—	(1,253)	—	—	—
Interest income and other[d]	—	—	—	186	—	—	—
Total consolidated	$ 15,184	$ —	$ 15,184	$ 2,862	$ 2,049	$ 4,076	$ 58,700
Year Ended December 31, 2005							
U.S. Franchised Electric and Gas	$ 5,413	$ 19	$ 5,432	$ 1,495	$ 962	$ 1,350	$ 18,739
Natural Gas Transmission	3,955	100	4,055	1,388	458	930	18,823
Field Services[f]	5,470	60	5,530	1,946	143	86	1,377
Commercial Power[e]	102	46	148	(118)	60	2	1,619
International Energy	745	—	745	314	64	23	2,962
Crescent[c][g]	495	—	495	314	1	599	1,507
Total reportable segments	16,180	225	16,405	5,339	1,688	2,990	45,027
Other[e]	117	(45)	72	(518)	40	29	9,402
Eliminations and reclassifications	—	(180)	(180)	—	—	—	294
Interest expense	—	—	—	(1,066)	—	—	—
Interest income and other[d]	—	—	—	56	—	—	—
Total consolidated	$ 16,297	$ —	$ 16,297	$ 3,811	$ 1,728	$ 3,019	$ 54,723
Year Ended December 31, 2004							
U.S. Franchised Electric and Gas	$ 5,045	$ 24	$ 5,069	$ 1,467	$ 863	$ 1,126	$ 18,062
Natural Gas Transmission	3,194	157	3,351	1,329	431	544	17,783
Field Services[f]	10,036	8	10,044	367	285	202	6,265
Commercial Power[e]	(26)	205	179	(479)	69	7	1,726
International Energy	619	—	619	222	58	28	3,058
Crescent[c][g]	437	—	437	240	2	568	1,317
Total reportable segments	19,305	394	19,699	3,146	1,708	2,475	48,211
Other[e]	291	(100)	191	(207)	42	54	7,139
Eliminations and reclassifications	—	(294)	(294)	—	—	—	420
Interest expense	—	—	—	(1,282)	—	—	—
Interest income and other[d]	—	—	—	96	—	—	—
Total consolidated	$ 19,596	$ —	$ 19,596	$ 1,753	$ 1,750	$ 2,529	$ 55,770

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

(a) Segment results exclude results of entities classified as discontinued operations

(b) Includes assets held for sale

(c) Capital expenditures for residential real estate are included in operating cash flows and were $322 million for the period from January 1, 2006 through the date of deconsolidation (September 7, 2006), $355 million in 2005 and $322 million in 2004.

(d) Other includes foreign currency transaction gains and losses, and additional minority interest expense not allocated to the segment results.

(e) Amounts associated with former DENA operations are included in Other for all periods presented, except for the Midwestern generation and Southeast operations, which are reflected in Commercial Power.

(f) In July 2005, Duke Energy completed the agreement with ConocoPhillips to reduce Duke Energy's ownership interest in DEFS from 69.7% to 50% Field Services segment data includes DEFS as a consolidated entity for periods prior to July 1, 2005 and as an equity method investment for periods after June 30, 2005.

(g) In September 2006, Duke Energy completed a joint venture transaction of Crescent (see Note 2). As a result, Crescent segment data includes Crescent as a consolidated entity for periods prior to September 7, 2006 and as an equity method investment for periods subsequent to September 7, 2006.

Geographic Data

	U.S.	Canada	Latin America	Other Foreign	Consolidated
			(in millions)		
2006					
Consolidated revenues	$10,710	$ 3,472	$ 961	$ 41	$ 15,184
Consolidated long-lived assets	43,468	10,541	2,474	245	56,728
2005					
Consolidated revenues	$12,147	$ 3,366	$ 740	$ 44	$ 16,297
Consolidated long-lived assets	29,658	10,544	2,241	228	42,671
2004					
Consolidated revenues	$16,861	$ 2,067	$ 611	$ 57	$ 19,596
Consolidated long-lived assets	30,960	9,902	2,136	233	43,231

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

4. Regulatory Matters

Regulatory Assets and Liabilities. Duke Energy's regulated operations are subject to SFAS No. 71. Accordingly, Duke Energy records assets and liabilities that result from the regulated ratemaking process that would not be recorded under GAAP for non-regulated entities. (For further information see Note 1.)

Duke Energy's Regulatory Assets and Liabilities:

	As of December 31,		
	2006	2005	Recovery/Refund Period Ends
	(in millions)		
Regulatory Assets[(a)]			
Net regulatory asset related to income taxes[(b)]	$1,361	$ 1,338	(l)
Accrued pension and post retirement[(c)(r)]	975	—	(p)
ARO costs[(c)]	463	546	2043
Regulatory Transition Charges (RTC)[(c)]	331	—	2011
Gasification services agreement buyout costs[(c)]	207	—	2018
Deferred debt expense[(d)]	192	166	2039
Vacation accrual[(c)]	121	80	2007
Post-in-service carrying costs and deferred operating expense[(c)]	92	—	2065
Under-recovery of fuel costs[(f)(i)]	61	—	2008
Hedge costs and other deferrals[(c)]	48	—	2007
Regional Transmission Organization (RTO)[(q)]	41	41	(o)
Other[(c)]	180	148	(p)
Total Regulatory Assets	$4,072	$ 2,319	
Regulatory Liabilities[(a)]			
Removal costs[(d)(h)]	$2,345	$ 1,670	(n)
Other deferred tax credits[(d)(f)(h)]	5	8	(f)
Nuclear property and liability reserves[(d)(h)]	173	167	2043
Gas purchase costs[(g)]	173	—	2007
Purchased capacity costs[(e)(j)]	107	121	(k)
Demand-side management costs[(e)(h)]	78	59	(m)
Deferred emission allowance revenue	41	—	(p)
Over-recovery of fuel costs[(f)(g)]	20	76	2007
North Carolina clean air compliance[(d)(h)]	—	164	2011
Other[(h)]	116	73	(p)
Total Regulatory Liabilities	$3,058	$ 2,338	

(a) All regulatory assets and liabilities are excluded from rate base unless otherwise noted.

(b) Natural Gas Transmission's amounts of $848 million at December 31, 2006 and $954 million at December 31, 2005 are expected to be included in future rate filings. U.S. Franchised Electric and Gas's amounts of $513 million at December 31, 2006 and $384 million at December 31, 2005 are included in rate base.

(c) Included in Other Regulatory Assets and Deferred Debits on the Consolidated Balance Sheets.

(d) Included in rate base.

(e) Earns a negative return.

(f) In 2005, Duke Energy Carolinas reduced the previously recorded excess deferred tax liability by approximately $150 million. Additionally, in 2005, Duke Energy Carolinas received approval from the NCUC to credit approximately $100 million against fuel rates for North Carolina retail customers. Similarly, the PSCSC granted approval to credit approximately $40 million against fuel rates for South Carolina retail customers. These amounts were credited to customer rates during 2006 and 2005. The remaining reduction was achieved by crediting fuel rates for certain wholesale customers and writing off a portion of the balance against income.

(g) Included in Accounts Payable on the Consolidated Balance Sheets.

(h) Included in Other Deferred Credits and Other Liabilities on the Consolidated Balance Sheets.

(i) Included in Receivables on the Consolidated Balance Sheets.

(j) Included in Other Current Liabilities and Other Deferred Credits and Other Liabilities on the Consolidated Balance Sheets.

(k) Incurred costs were deferred and are being recovered in rates. U.S. Franchised Electric and Gas is currently over–recovered for these costs and is refunding the liability through retail rates. Refund period will be determined by the volume of sales.

(l) Recovery/refund is over the life of the associated asset or liability.

(m) Incurred costs were deferred and are being recovered in rates. U.S. Franchised Electric and Gas is currently over–recovered for these costs in the South Carolina jurisdiction. Refund period is dependent on volume of sales and cost incurrence.

(n) Liability is extinguished over the lives of the associated assets.

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

(o) To be recovered through future transmission rates. Recovery period currently unknown.

(p) Recovery/Refund period currently unknown.

(q) Investment in RTO reclassified as regulatory asset from Other Deferred Credits during 2005 after termination of GridSouth Transco project.

(r) Includes $595 million related to adoption of SFAS No. 158 (see Note 22) and $380 million related to impacts of purchase accounting as a result of the merger with Cinergy (see Note 2).

Regulatory Merger Approvals. As discussed in Note 1 and Note 2, on April 3, 2006, the merger between Duke Energy and Cinergy was consummated to create a newly formed company, Duke Energy Holding Corp. (subsequently renamed Duke Energy Corporation). As a condition to the merger approval, the PUCO, the KPSC, the PSCSC and the NCUC required that certain merger related savings be shared with consumers in Ohio, Kentucky, South Carolina, and North Carolina, respectively. The commissions also required Duke Energy Holding Corp., Cinergy, Duke Energy Ohio, Duke Energy Kentucky, and/or Duke Energy Carolinas to meet additional conditions. While the merger itself was not subject to approval by the IURC, the IURC approved certain affiliate agreements in connection with the merger subject to similar conditions. Key elements of these conditions include:

- The PUCO required that Duke Energy Ohio provide (i) a rate reduction of approximately $15 million for one year to facilitate economic development in a time of increasing rates and market prices (ii) a reduction of approximately $21 million to its gas and electric consumers in Ohio for one year, with both credits beginning January 1, 2006. In April 2006, the Office of the Ohio Consumers' Council (OCC) filed a Notice of Appeal with the Supreme Court of Ohio, requesting the Court remand the PUCO's merger approval for a full evidentiary hearing. The OCC alleged that the PUCO improperly failed to: (i) set the matter for a full evidentiary hearing; (ii) consider evidence regarding the transfer of certain DENA assets to Duke Energy Ohio; and (iii) lift the stay on discovery. Duke Energy Ohio and the OCC settled this matter and in June 2006, the Court granted the OCC's motion to dismiss. As of December 31, 2006, Duke Energy Ohio has returned $14 million and $20 million, respectively, on each of these rate reductions.

- The KPSC required that Duke Energy Kentucky provide $8 million in rate reductions to its customers over five years, ending when new rates are established in the next rate case after January 1, 2008. As of December 31, 2006, Duke Energy Kentucky has returned $1 million to customers on this rate reduction.

- The PSCSC required that Duke Energy Carolinas provide a $40 million rate reduction for one year and a three-year extension to the Bulk Power Marketing profit sharing arrangement. Approximately $23 million of the rate reduction has been passed through to customers since the ruling by the PSCSC.

- The NCUC required that Duke Energy Carolinas provide (i) a rate reduction of approximately $118 million for its North Carolina customers through a credit rider to existing base rates for a one-year period following the close of the merger, and (ii) $12 million to support various low income, environmental, economic development and educationally beneficial programs, the cost of which was incurred in the second quarter of 2006. Approximately $54 million of the rate reduction has been passed through to customers since the ruling by the NCUC.

  In its order approving Duke Energy's merger with Cinergy, the NCUC stated that the merger will result in a significant change in Duke Energy's organizational structure which constitutes a compelling factor that warrants a general rate review. Therefore, as a condition of its merger approval and no later than June 1, 2007, Duke Energy Carolinas is required to file a general rate case or demonstrate that Duke Energy Carolinas' existing rates and charges should not be changed. This review will be consolidated with the proceeding that the NCUC is required to undertake in connection with the North Carolina clean air legislation to review Duke Energy Carolinas' environmental compliance costs. The NCUC specifically noted that it has made no determination that the rates currently being charged by Duke Energy Carolinas are, in fact, unjust or unreasonable.

- The IURC required that Duke Energy Indiana provide a rate reduction of $40 million to its customers over a one year period and $5 million over a five year period for low-income energy assistance and clean coal technology. In April 2006, Citizens Action Coalition of Indiana, Inc., an intervenor in the merger proceeding, filed a Verified Petition for Rehearing and Reconsideration claiming that Duke Energy Indiana should be ordered to provide an additional $5 million in rate reduction to customers to be consistent with the terms of the NCUC's order approving the merger. In May 2006, the IURC denied the petition for rehearing and reconsideration. As of December 31, 2006, Duke Energy Indiana has returned approximately $27 million to customers on this rate reduction.

- The FERC approved the merger without conditions. In January 2006, Public Citizen's Energy Program, Citizens Action Coalition of Indiana, Inc., Ohio Partners for Affordable Energy and Southern Alliance for Clean Energy requested rehearing of the FERC approval. In February 2006, the FERC issued an order granting rehearing of FERC's order for further consideration. On February 5, 2007, after further consideration, the FERC issued an order dismissing the request for a rehearing.

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

Spent Nuclear Fuel. Under provisions of the Nuclear Waste Policy Act of 1982, Duke Energy contracted with the DOE for the disposal of spent nuclear fuel. The DOE failed to begin accepting spent nuclear fuel on January 31, 1998, the date specified by the Nuclear Waste Policy Act and in Duke Energy's contract with the DOE. In 1998, Duke Energy filed a claim with the U.S. Court of Federal Claims against the DOE related to the DOE's failure to accept commercial spent nuclear fuel by the required date. Damages claimed in the lawsuit are based upon Duke Energy's costs incurred as a result of the DOE's partial material breach of its contract, including the cost of securing additional spent fuel storage capacity. The matter has been stayed pending the result of ongoing settlement negotiations between Duke Energy and the DOE. Duke Energy will continue to safely manage its spent nuclear fuel until the DOE accepts it. Payments made to the DOE for expected future disposal costs are based on nuclear output and are included in the Consolidated Statements of Operations as Fuel Used in Electric Generation and Purchased Power. Duke Energy expects resolution of this matter in the first quater of 2007.

U.S. Franchised Electric and Gas. *Rate Related Information.* The NCUC, PSCSC, IURC and KPSC approve rates for retail electric and gas sales within their states. The PUCO approves rates and market prices for retail electric and gas sales within Ohio. The FERC approves rates for electric sales to wholesale customers served under cost-based rates.

NC Clean Air Act Compliance. In 2002, the state of North Carolina passed clean air legislation that freezes electric utility rates from June 20, 2002 to December 31, 2007 (rate freeze period), subject to certain conditions, in order for North Carolina electric utilities, including Duke Energy Carolinas, to significantly reduce emissions of sulfur dioxide (SO_2) and nitrogen oxides (NOx) from coal-fired power plants in the state. The legislation allows electric utilities, including Duke Energy Carolinas, to accelerate the recovery of compliance costs by amortizing them over seven years (2003–2009). The legislation provides for significant flexibility in the amount of annual amortization recorded, allowing utilities to vary the amount amortized, within limits, although the legislation does require that a minimum of 70% of the originally estimated total cost of $1.5 billion be amortized within the rate freeze period (2002 to 2007). Duke Energy Carolinas' amortization expense related to this clean air legislation totals approximately $863 million from inception, with approximately $225 million, $311 million and $211 million recorded during the years ended 2006, 2005 and 2004, respectively. As of December 31, 2006, cumulative expenditures totaled approximately $828 million, with $403 million, $310 million, and $106 million incurred during the years ended December 31, 2006, 2005 and 2004, respectively, and are included within capital expenditures in Net Cash Used In Investing Activities on the Consolidated Statements of Cash Flows. In filings with the NCUC, Duke Energy Carolinas has estimated the costs to comply with the legislation as approximately $1.7 billion. Actual costs may be higher than the estimate based on changes in construction costs and Duke Energy Carolinas' continuing analysis of its overall environmental compliance plan. Any change in compliance costs will be included in future filings with the NCUC. Additionally, federal, state and environmental regulations, including, among other things, the Clean Air Interstate Rule (CAIR), and the Clean Air Mercury Rule (CAMR) could result in additional costs to reduce emissions from our coal-fired power plants.

Duke Energy Indiana Environmental Compliance Case. In November 2004, Duke Energy Indiana applied to the IURC for approval of its plan for complying with SO_2, NOx, and mercury emission reduction requirements. Duke Energy Indiana also requested approval of cost recovery for certain proposed compliance projects. An evidentiary hearing was held in May 2005. In December 2005, Duke Energy Indiana, the Indiana Office of Utility Consumer Counselor (OUCC), and the Duke Energy Indiana Industrial Group filed a settlement agreement providing for approval of Duke Energy Indiana's compliance plan, and approval of financing, depreciation, and operation and maintenance cost recovery. In May 2006, the IURC approved the settlement agreement in its entirety. The approved Settlement Agreement provides for: (1) the construction of Phase 1 CAIR and Clean Air Mercury Rule (CAMR) projects with estimated expenditures of approximately $1.08 billion, (2) timely recovery of financing, construction, operation and maintenance cost and depreciation associated with the Phase 1 CAIR and CAMR plan, (3) recovery of emission allowances in connection with SO_2, NOx and mercury, (4) accelerated 20 year depreciation rate, (5) timely recovery of Phase 1 plan development and presentation costs and Phase 2 plan development, engineering and pre-construction, and coal and equipment testing costs, and (6) authority to defer post-in-service AFUDC, depreciation costs and operation and maintenance cost until applicable costs are reflected in rates.

Duke Energy Ohio Electric Rate Filings. Duke Energy Ohio operates under a RSP, a Market Based Standard Service Offer (MBSSO) approved by the PUCO in November 2004. In March 2005, the OCC appealed the PUCO's approval of the MBSSO to the Supreme Court of Ohio and the court issued its decision in November 2006. It upheld the MBSSO in virtually every respect but remanded to the PUCO on two issues. The Court ordered the PUCO to support a certain portion of its order with reasoning and record evidence and to require Duke Energy Ohio to disclose certain confidential commercial agreements with other parties previously requested by the OCC. Duke Energy Ohio has complied with the disclosure order. Such confidential commercial agreements are relatively common in the jurisdiction and the PUCO has not allowed production of such agreements in past cases in which the PUCO was presented with a settlement agreement on the basis that they are irrelevant. A hearing on remand is expected in March 2007. Duke Energy Ohio has filed for a regulatory extension of the RSP through 2010.

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

On August 2, 2006, Duke Energy Ohio filed an application with the PUCO to amend its MBSSO. The proposal provides for continued electric system reliability, a simplified market price structure and clear price signals for customers, while helping to maintain a stable revenue stream for Duke Energy Ohio. The application is pending and Duke Energy Ohio cannot predict the outcome of this proceeding.

Duke Energy Ohio's MBSSO includes a fuel clause recovery component which is audited annually by the PUCO. In January 2006, Duke Energy Ohio entered into a settlement resolving all open issues identified in the 2005 audit. The PUCO approved the settlement in February 2006. Duke Energy and Duke Energy Ohio do not expect the agreement to have a material impact on their consolidated results of operations, cash flows or financial position.

In addition to the fuel clause recovery component, Duke Energy Ohio's MBSSO includes a reserve capacity component known as the System Reliability Tracker, and an Annually Adjusted Component to recover environmental, tax and homeland security costs. In 2006, Duke Energy Ohio filed an application requesting to modify each of these components. After the Ohio Supreme Court issued its remand order in the MBSSO appeal, the PUCO issued an order permitting Duke Energy Ohio to continue to charge its existing market prices (except for the System Reliability Tracker) with true-up to actual costs to be decided at a later date. The PUCO allowed Duke Energy Ohio's System Reliability Tracker to expire by its terms on January 1, 2007. In the meantime, consideration of Duke Energy Ohio's proposed modifications is suspended pending the outcome of the remand case. Duke Energy Ohio does not expect a significant change, if any to the MBSSO components but cannot predict the outcome of the cases. The PUCO is expected to decide these matters in 2007.

Duke Energy Kentucky Electric Rate Case. In May 2006, Duke Energy Kentucky filed an application for an increase in its base electric rates. The application, which sought an increase of approximately $67 million in revenue, or approximately 28 percent, to be effective in January 2007, was filed pursuant to the KPSC's 2003 Order approving the transfer of 1,100 MW of generating assets from Duke Energy Ohio to Duke Energy Kentucky. Duke Energy Kentucky also sought to reinstitute its fuel cost recovery mechanism which had been frozen since 2001, and has proposed to refresh the pricing for the back-up power supply contract to reflect current market pricing. In the fourth quarter of 2006, Duke Energy Kentucky reached a settlement agreement in principle with all parties to this proceeding resolving all the issues raised in the proceeding. Among other things, the settlement agreement provided for a $49 million increase in Duke Energy Kentucky's base electric rates and reinstitution of the fuel cost recovery mechanism. In December 2006, the KPSC approved the settlement agreement.

Duke Energy Kentucky Gas Rate Cases. In 2002, the KPSC approved Duke Energy Kentucky's gas base rate case which included, among other things, recovery of costs associated with an accelerated gas main replacement program. The approval authorized a tracking mechanism to recover certain costs including depreciation and a rate of return on the program's capital expenditures. The Kentucky Attorney General appealed to the Franklin Circuit Court the KPSC's approval of the tracking mechanism as well as the KPSC's subsequent approval of annual rate adjustments under this tracking mechanism. In 2005, both Duke Energy Kentucky and the KPSC requested that the court dismiss these cases. At the present time, Duke Energy and Duke Energy Kentucky cannot predict the timing or outcome of this litigation.

In February 2005, Duke Energy Kentucky filed a gas base rate case with the KPSC requesting approval to continue the tracking mechanism and for a $14 million annual increase in base rates. A portion of the increase is attributable to recovery of the current cost of the accelerated main replacement program in base rates. In December 2005, the KPSC approved an annual rate increase of $8 million and re-approved the tracking mechanism through 2011. In February 2006, the Kentucky Attorney General appealed the KPSC's order to the Franklin Circuit Court, claiming that the order improperly allows Duke Energy Kentucky to increase its rates for gas main replacement costs in between general rate cases, and also claiming that the order improperly allows Duke Energy Kentucky to earn a return on investment for the costs recovered under the tracking mechanism which permits Duke Energy Kentucky to recover its gas main replacement costs. At this time, Duke Energy and Duke Energy Kentucky cannot predict the outcome of this litigation.

Bulk Power Marketing (BPM) Profit Sharing. The NCUC approved Duke Energy Carolinas' proposal in June 2004 to share an amount equal to fifty percent of the North Carolina retail allocation of the profits from certain wholesale sales of bulk power from Duke Energy Carolinas' generating units at market based rates (BPM Profits). Duke Energy Carolinas also informed the NCUC that it would no longer include BPM Profits in calculating its North Carolina retail jurisdictional rate of return for its quarterly reports to the NCUC. As approved by the NCUC, the sharing arrangement provides for fifty percent of the North Carolina allocation of BPM Profits to be distributed through various assistance programs, up to a maximum of $5 million per year. Any amounts exceeding the maximum are used to reduce rates for industrial customers in North Carolina.

On June 28, 2006, the NCUC issued an order ruling on a dispute between Duke Energy Carolinas, the NCUC Public Staff and the Carolina Utility Customers Association (CUCA) regarding the method for determining the incremental costs of emission allowances used

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

to calculate the BPM Profits under the sharing arrangement. The Public Staff and CUCA each proposed methods that differ from the method intended by Duke Energy Carolinas when it initially requested approval of the sharing arrangement. Duke Energy Carolinas has consistently used its originally intended method since it first implemented the sharing arrangement. The NCUC adopted the Public Staff's method and ordered Duke Energy Carolinas to file and implemented a revised rate rider. This ruling resulted in an $18 million charge during the year ended December 31, 2006, of which $11 million related to wholesale sales in 2005. On July 17, 2006, Duke Energy Carolinas filed a Motion for Reconsideration requesting that the NCUC reconsider its June 28, 2006 order. In the alternative, Duke Energy Carolinas requested that the NCUC make its order effective only prospectively with respect to sharing periods beginning January 1, 2007. Duke Energy Carolinas also requested that if the NCUC was not inclined to grant its request to reinstate its proposed rider, then the NCUC should approve Duke Energy Carolinas' withdrawal of the rider at its option. On September 15, 2006, Duke Energy Carolinas and the Public Staff filed an Offer of Settlement under which Duke Energy's method would be used through June 30, 2006 and the Public Staff's method would be used from July 1, 2006 through the end of the sharing arrangement. Additionally, the sharing arrangement would be extended for the shorter of 1 year (through December 31, 2008) or the effective date of a general rate order from the NCUC addressing the ratemaking treatment of BPM revenues. In December 2006, the NCUC approved the settlement, after an evidentiary hearing, and Duke Energy Carolinas reversed the $18 million charge previously recognized.

Other. U.S. Franchised Electric and Gas is engaged in planning efforts to meet projected load growth in its service territory. Long-term projections indicate a need for significant capacity additions, which may include new nuclear, integrated gasification combined cycle (IGCC), coal facilities or gas fired generation units. Because of the long lead times required to develop such assets, U.S. Franchised Electric and Gas is taking steps now to ensure those options are available. In March 2006, Duke Energy Carolinas announced that it has entered into an agreement with Southern Company to evaluate potential construction of a new nuclear plant at a site jointly owned in Cherokee County, South Carolina. With selection of the Cherokee County site, Duke Energy Carolinas is moving forward with previously announced plans to develop an application to the U.S. Nuclear Regulatory Commission (NRC) for a combined construction and operating license (COL) for two Westinghouse AP1000 (advanced passive) reactors. Each reactor is capable of producing approximately 1,117 MW. The COL application submittal to the NRC is anticipated in late 2007 or early 2008. Submitting the COL application does not commit Duke Energy Carolinas to build nuclear units. On September 20, 2006, Duke Energy Carolinas filed an application with the NCUC for assurance that pursuit of the proposed nuclear plant (the William States Lee III Nuclear Station) is prudent and that Duke Energy Carolinas will be allowed to recover prudently incurred expenses related to its development and evaluation of the proposed William States Lee III Nuclear Station. Specifically, Duke Energy Carolinas requests an NCUC order (1) finding that work performed by Duke Energy Carolinas to ensure the availability of nuclear generation by 2016 for its customers is prudent and consistent with the promotion of adequate, reliable, and economical utility service to the citizens of North Carolina and the polices expressed in North Carolina General Statute 62-2, and (2) providing expressly that Duke Energy Carolinas may recover in rates, in a timely fashion, the North Carolina allocable portion of its share of costs prudently incurred to evaluate and develop a new nuclear generation facility through December 31, 2007, whether or not a new nuclear facility is constructed. The NCUC held oral arguments on January 9, 2007, and briefs were filed on February 14, 2007. Duke Energy Carolinas expects the NCUC to rule on its application in the first quarter of 2007.

On June 2, 2006, Duke Energy Carolinas also filed an application with the NCUC for a Certificate of Public Convenience and Necessity (CPCN) to construct two 800 MW state of the art coal generation units at its existing Cliffside Steam Station in North Carolina. The NCUC held public hearings in August 2006, and an evidentiary hearing in Raleigh, North Carolina concluded on September 14, 2006. Post-hearing briefs and proposed orders were filed on October 13, 2006. After the evidentiary hearing, Duke Energy Carolinas received competitive proposals for two major scopes of equipment for the Cliffside Project which suggest that the capital costs for these major components are increasing significantly due to various market pressures that will likely impact utility generation construction projects across the United States. In October 2006, Duke Energy made a filing with the NCUC related to the Duke Energy Carolinas' request for a CPCN for the Cliffside project. In this filing, Duke Energy stated that due to the rising costs described above, the cost of building the Cliffside units could be approximately $3 billion, excluding allowance for funds used during construction (AFUDC). The costs described above are expected to continue to increase causing the overall cost of the Cliffside project to increase, until such time as the NCUC issues a CPCN and Duke Energy is able to enter into definitive agreements with necessary material and service providers. The NCUC issued orders requiring additional public and evidentiary hearings. From January 17, 2007 to January 19, 2007 the NCUC held an evidentiary hearing to consider evidence limited to Duke Energy Carolinas updated cost information for the project. On February 28, 2007, the NCUC issued a notice of decision approving the construction of one unit at the Cliffside Steam Station. The NCUC stated that it will issue a full order in the near future. Duke Energy will review the NCUC's order, once issued, and determine whether to proceed with the Cliffside Project or consider other alternatives, including additional gas fired generation.

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

New energy legislation has been introduced in the current South Carolina legislative session. Key elements of the legislation include expansion of the annual fuel clause mechanism to include recovery of costs of reagents (ammonia, limestone, etc.) that are consumed in the operation of Duke Energy Carolina's SO_2 and NOx control technologies. The cost of reagents for Duke Energy Carolinas in 2007 is expected to be approximately $20 million. Subsequent to the enactment of any legislation, Duke Energy Carolinas then will be allowed to recover the South Carolina portion of these costs through the fuel clause. The legislation also includes provisions to provide cost recovery assurance for upfront development costs associated with nuclear baseload generation, cost recovery assurance for construction costs associated with nuclear or coal baseload generation, and the ability to recover financing costs for new nuclear or coal baseload generation through annual riders. Similar legislation is being discussed in North Carolina and may be introduced in the 2007 legislative session. At this time, Duke Energy Carolinas cannot determine which elements of any pending legislation will be passed into law or the potential financial impact of those legislative initiatives.

In August 2005, Duke Energy Indiana filed an application with the IURC for approval of study and preconstruction costs related to the joint development of an IGCC project with Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana, Inc. (Vectren). Duke Energy Indiana and Vectren reached a Settlement Agreement with the OUCC providing for the recovery of such costs if the IGCC project is approved and constructed and for the partial recovery of such costs if the IGCC project does not go forward. The IURC issued an order on July 26, 2006 approving the Settlement Agreement in its entirety.

On September 7, 2006, Duke Energy Indiana and Vectren filed a joint petition with the IURC seeking certificates of public convenience and necessity for the construction of a 630 MW IGCC power plant at Duke Energy Indiana's Edwardsport Generating Station in Knox County, Indiana. The petition describes the applicants' need for additional baseload generating capacity and requests timely recovery of all construction and operating costs related to the proposed generating station, including financing costs, together with certain incentive ratemaking treatment. Duke Energy Indiana and Vectren filed their cases in chief with the IURC on October 24, 2006. As with Duke Energy Carolinas' Cliffside project, Duke Energy Indiana's estimated costs for the potential IGCC project have also increased. Duke Energy Indiana's publicly filed testimony with the IURC indicates that industry (EPRI) total capital requirement estimates for a facility of this type and size are now in the range of $1.6 billion to $2.1 billion (including escalation to 2011 and owners' specific site costs). The case is scheduled for an evidentiary hearing in June 2007. On February 16, 2007, Duke Energy Indiana filed a request for deferral and subsequent cost recovery of the costs expected to be incurred prior to the anticipated date of an order by the IURC regarding Duke Energy Indiana's request for a certificate of public convenience and necessity for the construction of the Edwardsport Generating Station. These costs relate to the continued investigation, analysis and development of the IGCC project, and must be incurred, to assure the project can achieve a targeted in-service date of 2011.

On August 15, 2006, Duke Energy Indiana filed a petition with the IURC requesting recovery of its costs of purchasing electricity to be produced by a 100 megawatt wind energy farm under development pursuant to a 20-year purchased power agreement between Duke Energy Indiana and Benton County Wind Farm, LLC. The IURC issued an order on December 6, 2006 approving recovery of the retail portion of the purchased power cost plus the retail portion of Midwest ISO costs over the 20-year life of the agreement.

Duke Energy Indiana recovers its actual fuel costs quarterly through a rate adjustment mechanism. In two recent fuel clause proceedings, certain industrial customers and the Citizens Action Coalition of Indiana, Inc. have intervened and sub-dockets have been established to address issues raised by the OUCC and the intervenors concerning the allocation of fuel costs between native load customers and non-native load sales, the reasonableness of various Midwest Independent Transmission System Operator, Inc. (Midwest ISO) costs for which Duke Energy Indiana has sought recovery and Duke Energy Indiana's recovery of costs associated with certain power hedging activities. Duke Energy Indiana is defending its practices, its costs, and the allocation of such costs. A hearing was conducted in one of these proceedings on September 20, 2006. A decision is expected in the first quarter of 2007. An evidentiary hearing in the second proceeding is set to begin in May 2007. The IURC has authorized Duke Energy Indiana to collect through rates the costs which it sought recovery in the two sub-docket proceedings, subject to refund pending the outcome of these proceedings. Duke Energy cannot predict the outcome of these proceedings but does not expect the outcome to be material to its consolidated results of operations, cash flows or financial position.

In April 2005, the PUCO issued an order opening a statewide investigation into riser leaks in gas pipeline systems throughout Ohio. The investigation followed four explosions since 2000 caused by gas riser leaks, including an April 2000 explosion in Duke Energy Ohio's service area. In November 2006, the PUCO Staff released the expert report, which concluded that certain types of risers are prone to leaks under various conditions, including over-tightening during initial installation. The PUCO Staff recommended that natural gas companies continue to monitor the situation and study the cause of any further riser leaks to determine whether further remedial action is war —

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

ranted. Duke Energy Ohio has approximately 87,000 of these risers on its distribution system. If the PUCO orders natural gas companies to replace all of these risers, Duke Energy Ohio estimates a replacement cost of $35 million. At this time, Duke Energy Ohio cannot predict the outcome or the impact of the statewide Ohio investigation.

In April 2006, the FERC issued an order on the Midwest ISO's revisions to its Transmission and Energy Markets Tariffs regarding its RSG. The FERC found that the Midwest ISO violated the tariffs when it did not charge RSG costs to virtual supply offers. The FERC, among other things, ordered the Midwest ISO to recalculate the rate and make refunds to customers, with interest, to reflect the correct allocation of RSG costs. Duke Energy Shared Services, on behalf of Duke Energy Indiana and Duke Energy Ohio, filed a Request for Rehearing, and in October 2006, the FERC issued an order which, among other things, granted rehearing on the issue of refunds. The FERC stated that it would not require recalculation of the rates and, as such, refunds are no longer required. As a result, neither Duke Energy Ohio nor Duke Energy Indiana believe that this issue will have a material effect on their consolidated results of operations, cash flows, or financial position.

FERC To Issue Electric Reliability Standards. Consistent with reliability provisions of the Energy Policy Act of 2005, on July 20, 2006, FERC issued its Final Rule certifying NERC as the Electric Reliability Organization (ERO). NERC has filed over 100 proposed reliability standards with FERC. FERC's proposed action to approve a large number of these standards will result in those standards becoming mandatory and enforceable for the 2007 peak summer season. Other reliability standards will become mandatory and enforceable thereafter. Duke Energy does not believe that the issuance of these standards will have a material impact on its consolidated results of operations, cash flows, or financial position.

Duke Energy Carolinas "Independent Entity" to Perform Transmission Functions. On December 19, 2005, the FERC approved a plan filed by Duke Energy Carolinas to establish an "Independent Entity" (IE) to serve as a coordinator of certain transmission functions and an "Independent Monitor" (IM) to monitor the transparency and fairness of the operation of Duke Energy Carolinas' transmission system. Under the proposal, Duke Energy Carolinas remains the owner and operator of the transmission system with responsibility for the provision of transmission service under Duke Energy Carolinas' Open Access Transmission Tariff. Duke Energy Carolinas has retained the Midwest ISO to act as the IE and Potomac Economics, Ltd. to act as the IM. The IE and IM began operations on November 1, 2006. Duke Energy Carolinas is not at this time seeking adjustments to its transmission rates to reflect the incremental cost of the proposal, which is not projected to have a material adverse effect on Duke Energy's future consolidated results of operations, cash flows or financial position.

Natural Gas Transmission *Rate Related Information.* On August 17, 2006, the NEB approved a settlement for 2006 and 2007 tolls.

Union Gas has rates that are approved by the OEB. Effective January 1, 2006, Union Gas implemented new rates approved by the OEB in December 2005, reflecting items previously approved. Union Gas' earnings for 2006 continue to be subject to the earnings sharing mechanism implemented by the OEB in 2005.

In November 2006, Union Gas received a decision from the OEB on the regulation of rates for gas storage services in Ontario. The OEB found the storage market is competitive. As a result, the OEB will not regulate the rates for storage services to customers outside Union's franchise area or the rates for new storage services to customers within its franchise area. Existing storage services to customers within Union's franchise area will continue to be provided at regulated cost-based rates. The decision creates an unregulated storage operation within Union Gas, and provides support for new storage investment in Ontario.

In December 2006, the OEB issued a final rate order for new rates effective January 1, 2007. The average rate increase is approximately 3.1% and includes the impact of an increase in the common equity component of Union Gas' capital structures from 35% to 36% and a decrease in the allowed return of equity from 9.63% to 8.54%.

Rates for the sale of gas of Union Gas are adjusted quarterly to reflect updated commodity price forecasts. The difference between the approved and the actual cost of gas incurred in the current period is deferred for future recover from or return to customers, subject to approval by the OEB. These differences are directly flowed through to customers and, therefore, no rate of return is earned on the related deferred balances. The OEB's review and approval of these gas purchase costs primarily considers the prudence of the cost incurred.

As a result of the spin-off of the natural gas businesses to Spectra Energy effective January 2, 2007, the above matters related to Natural Gas Transmission will have no impact on Duke Energy's future consolidated results of operations, cash flows or financial position.

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

5. Joint Ownership of Generating and Transmission Facilities

Duke Energy Carolinas, along with North Carolina Municipal Power Agency Number 1, North Carolina Electric Membership Corporation, Piedmont Municipal Power Agency and Saluda River Electric Cooperative, Inc., have joint ownership of Catawba Nuclear Station, which is a facility operated by Duke Energy Carolinas. Duke Energy Ohio, Columbus Southern Power Company, and Dayton Power & Light jointly own electric generating units and related transmission facilities in Ohio. Duke Energy Ohio and Wabash Valley Power Association, Inc (WVPA) jointly own Vermillion Station. Additionally, Duke Energy Indiana is a joint-owner of Gibson Station Unit No. 5 with WVPA, and Indiana Municipal Power Agency (IMPA), as well as a joint-owner with WVPA and IMPA of certain Indiana transmission property and local facilities. These facilities constitute part of the integrated transmission and distribution systems, which are operated and maintained by Duke Energy Indiana.

As of December 31, 2006, Duke Energy's shares in jointly-owned plant or facilities were as follows:

	Ownership Share	Property, Plant, and Equipment	Accumulated Depreciation	Construction Work in Progress
		(in millions)		
Duke Energy Carolinas				
Production:				
Catawba Nuclear Station (Units 1 and 2) (c)	12.5 %	$ 563	$ 302	$ 10
Duke Energy Ohio				
Production:				
Miami Fort Station (Units 7 and 8) (b)	64.0	330	147	197
W.C. Beckjord Station (Unit 6) (b)	37.5	46	32	3
J.M. Stuart Station(a) (b)	39.0	420	179	153
Conesville Station (Unit 4)(a) (b)	40.0	81	52	28
W.M. Zimmer Station(b)	46.5	1,315	482	10
Killen Station(a) (b)	33.0	210	122	44
Vermillion(b)	75.0	197	34	—
Transmission	Various	88	47	1
Duke Energy Indiana				
Production:				
Gibson Station (Unit 5) (c)	50.05	287	146	6
Transmission and local facilities	94.28	2,740	1,126	—
Duke Energy Kentucky				
Production:				
East Bend Station(c)	69.0	423	217	4

(a) Station is not operated by Duke Energy Ohio.

(b) Included in Commercial Power segment

(c) Included in U.S. Franchised Electric and Gas segment

In December 2006, Duke Energy announced an agreement to purchase a portion of Saluda River Electric Cooperative, Inc.'s ownership interest in the Catawba Nuclear Station. Under the terms of the agreement, Duke Energy will pay approximately $158 million for the additional ownership interest of the Catawba Nuclear Station. Following the closing of the transaction, Duke Energy will own approximately 19 percent of the Catawba Nuclear Station. This transaction, which is expected to close prior to September 30, 2008, is subject to approval by various state and federal agencies.

Duke Energy's share of revenues and operating costs of the above jointly owned generating facilities are included within the corresponding line on the Consolidated Statements of Operations.

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

6. Income Taxes

The following details the components of income tax expense:

Income Tax Expense

	For the Years Ended December 31,		
	2006	2005	2004
	(in millions)		
Current income taxes			
Federal	$ 893	$ 845	$ (61)
State	67	138	17
Foreign	154	100	84
Total current income taxes	1,114	1,083	40
Deferred income taxes			
Federal	(248)	174	555
State	(9)	(39)	(119)
Foreign	(2)	74	42
Total deferred income taxes	(259)	209	478
Investment tax credit amortization	(12)	(10)	(11)
Total income tax expense from continuing operations	843	1,282	507
Total income tax expense (benefit) from discontinued operations	(14)	(430)	54
Total income tax benefit from cumulative effect of change in accounting principle	—	(1)	—
Total income tax expense presented in Consolidated Statements of Operations	$ 829	$ 851	$ 561

Earnings from Continuing Operations before Income Taxes

	For the Years Ended December 31,		
	2006	2005	2004
	(in millions)		
Domestic	$2,279	$3,220	$1,295
Foreign	583	591	458
Total earnings from continuing operations before income taxes	$2,862	$3,811	$1,753

Reconciliation of Income Tax Expense at the U.S. Federal Statutory Tax Rate to the Actual Tax Expense from Continuing Operations (Statutory Rate Reconciliation)

	For the Years Ended December 31,		
	2006	2005	2004
	(in millions)		
Income tax expense (benefit), computed at the statutory rate of 35%	$1,002	$1,334	$614
State income tax, net of federal income tax effect	38	64	(66)
Tax differential on foreign earnings	(52)	(33)	(34)
Employee stock ownership plan dividends	(29)	(22)	(19)
US tax on repatriation of foreign earnings	—	(2)	36
Other items, net	(116)	(59)	(24)
Total income tax expense from continuing operations	$ 843	$1,282	$507
Effective tax rate	29.5%	33.6%	28.9%

During 2006, Duke Energy had favorable tax settlements on research and development costs and nuclear decommissioning costs of approximately $30 million, tax benefits related to the impairment of an investment in Bolivia of approximately $25 million and tax credits recognized on synthetic fuel operations of approximately $20 million. The reduction in 2006 is reflected in the above table in Other Items, net.

During 2005, Duke Energy reorganized various entities and reestimated its liability which enabled it to reduce the $45 million tax liability to $39 million. The reduction in 2005 is included in the Statutory Rate Reconciliation as follows: Federal income taxes of $2 million are included in "U.S. tax on repatriation of foreign earnings" and $4 million of state taxes are included in "State income tax, net of federal income tax effect."

During 2004, Duke Energy recorded a $52 million income tax benefit from the reduction of state and federal income tax reserves based on the resolution in the second quarter of 2004 of several tax issues. The $52 million benefit is included in the Statutory Rate Reconciliation as follows: a $39 million state benefit is included in "State income tax, net of federal income tax effect" and a $13 million federal benefit is included in "Other items, net".

During 2004, Duke Energy recorded a $20 million income tax benefit from the change in state tax rates relating to deferred taxes as a result of a reorganization of certain subsidiaries. The $20 million benefit is included in "State income tax, net of federal income tax effect" in the Statutory Rate Reconciliation.

During 2004, Duke Energy recorded a $45 million income tax expense for the repatriation of foreign earnings which occurred during 2005 related to the American Jobs Creation Act of 2004. The $45 million is included in the Statutory Rate Reconciliation as follows: Federal income taxes of $36 million are included in "US tax on repatriation of foreign earnings," $4 million of state taxes are included in "State income tax, net of federal income tax effect," and $5 million of foreign taxes are included in "Tax differential on foreign earnings."

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

Net Deferred Income Tax Liability Components

	December 31,	
	2006	2005
	(In millions)	
Deferred credits and other liabilities	$ 1,657	$ 1,364
Other	167	60
Total deferred income tax assets	1,824	1,424
Valuation allowance	(20)	(26)
Net deferred income tax assets	1,804	1,398
Investments and other assets	(1,359)	(1,444)
Accelerated depreciation rates	(4,740)	(3,233)
Regulatory assets and deferred debits	(2,244)	(1,692)
Total deferred income tax liabilities	(8,343)	(6,369)
Total net deferred income tax liabilities	$(6,539)	$(4,971)

The above amounts have been classified in the Consolidated Balance Sheets as follows:

Deferred Tax Liabilities

	December 31,	
	2006	2005
	(in millions)	
Current deferred tax assets, included in other current assets	$ 357	$ 68
Non-current deferred tax assets, included in other investments and other assets	153	254
Current deferred tax liabilities, included in other current liabilities	(46)	(40)
Non-current deferred tax liabilities	(7,003)	(5,253)
Total net deferred income tax liabilities	$(6,539)	$(4,971)

As of December 31, 2006, Duke Energy has net operating loss carryforwards of approximately $20 million relating to state income taxes which mostly expire in years 2016 and later.

Although the outcome of tax audits is uncertain, management believes that adequate provisions for income and other taxes, such as sales and use, franchise, and property, have been made for potential liabilities resulting from such matters. As of December 31, 2006, Duke Energy has total provisions of approximately $190 million for uncertain tax positions, as compared to approximately $150 million as of December 31, 2005, including interest. The increase in total provisions since December 31, 2005 is primarily attributable to the merger with Cinergy. Management is not aware of any issues for open tax years that upon final resolution are expected to have a material adverse effect on Duke Energy's consolidated results of operations, cash flows or financial position.

Valuation allowances have been established for certain foreign and state net operating loss carryforwards that reduce deferred tax assets to an amount that will, more likely than not, be realized. The net change in the total valuation allowance is included in "Tax differential on foreign earnings" and "State income tax, net of federal income tax effect" lines of the Statutory Rate Reconciliation

On October 22, 2004, the President of the United States signed the American Jobs Creation Act of 2004 (The Act). The Act provides a deduction for income from qualified domestic production activities, which will be phased in from 2005 to 2010.

Under the guidance in FSP No. FAS 109-1, which was issued in December 2004, the deduction will be treated as a "special deduction" as described in SFAS No. 109. As such, for Duke Energy, the special deduction had no material impact on deferred tax assets and liabilities existing at the enactment date. Rather, the impact of this special deduction will be reported in the periods in which the deductions are claimed on the tax returns. For the year ended December 31, 2006, Duke Energy did not recognize any benefit relating to the deduction from qualified domestic activities.

In addition to the qualified domestic production activities deduction discussed above, the Act creates a temporary incentive for U.S. corporations to repatriate accumulated income earned abroad by providing an 85 percent dividends received deduction for certain divi —

dends from controlled foreign corporations. FSP No. FAS 109-2, which was issued in December 2004, states that a company is allowed time beyond the financial reporting period of enactment to evaluate the effect of the Act on its plan for reinvestment or repatriation of foreign earnings, as it applies to the application of SFAS No. 109. Although the deduction is subject to a number of limitations and some uncertainty remains as to how to interpret numerous provisions in the Act, Duke Energy recorded a $45 million tax liability at December 31, 2004 based upon Duke Energy's plans that it would repatriate approximately $500 million in extraordinary dividends in 2005. In 2005, Duke Energy repatriated approximately $500 million in extraordinary dividends. During this process, Duke Energy reorganized various entities and reduced its liability from $45 million to $39 million. There is no remaining liability as of December 31, 2006 and 2005.

Deferred income taxes and foreign withholding taxes have not been provided on the remaining undistributed earnings of Duke Energy's foreign subsidiaries as such amounts are deemed to be permanently reinvested. The cumulative undistributed earnings as of December 31, 2006 on which Duke Energy has not provided deferred income taxes and foreign withholding taxes, is approximately $420 million.

7. Asset Retirement Obligations

In June 2001, the FASB issued SFAS No. 143, which was adopted by Duke Energy on January 1, 2003 and addresses financial accounting and reporting for legal obligations associated with the retirement of tangible long-lived assets and the related asset retirement costs. The standard applies to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or normal use of the asset. SFAS No. 143 requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred, if a reasonable estimate of fair value can be made. The fair value of the liability is added to the carrying amount of the associated asset. This additional carrying amount is then depreciated over the life of the asset. The liability increases due to the passage of time based on the time value of money until the obligation is settled. Subsequent to the initial recognition, the liability is adjusted for any revisions to the expected value of the retirement obligation (with corresponding adjustments to property, plant, and equipment), and for accretion of the liability due to the passage of time. Additional depreciation expense is recorded prospectively for any property, plant and equipment increases.

Asset retirement obligations at Duke Energy relate primarily to the decommissioning of nuclear power facilities, the retirement of certain gathering pipelines and processing facilities, obligations related to right-of-way agreements, asbestos removal and contractual leases for land use. In accordance with SFAS No. 143, Duke Energy identified certain assets that have an indeterminate life, and thus the fair value of the retirement obligation is not reasonably estimable. These assets included on-shore and some off-shore pipelines, certain processing plants and distribution facilities and some gas-fired power plants. A liability for these asset retirement obligations will be recorded when a fair value is determinable.

Upon adoption of SFAS No. 143, Duke Energy's regulated electric and regulated natural gas operations classified removal costs for property that does not have an associated legal retirement obligation as a regulatory liability, in accordance with regulatory treatment under SFAS No. 71. Duke Energy does not accrue the estimated cost of removal when no legal obligation associated with retirement or removal exists for any of our non-regulated assets (including Duke Energy Ohio's generation assets). The total amount of removal costs included in Other Deferred Credits and Other Liabilities on the Consolidated Balance Sheets was $2,345 million and $1,670 million as of December 31, 2006 and 2005, respectively, which consisted of $1,954 million and $1,320 million, respectively, related to regulated electric operations and $391 million and $350 million, respectively, related to regulated natural gas operations.

The adoption of SFAS No. 143 had no impact on the income of the regulated electric operations, as the effects were offset by the establishment of regulatory assets and liabilities pursuant to SFAS No. 71 as Duke Energy received approval from both the NCUC and PSCSC to defer all cumulative and future income statement impacts related to SFAS No. 143.

In March 2005, the FASB issued FIN 47. As a result of the adoption of FIN 47 in 2005, an increase in total assets of $31 million was recorded, consisting of an increase in regulatory assets of $24 million, an increase in net property, plant and equipment of $7 million and an increase in ARO liabilities of approximately $35 million. The adoption of FIN 47 had no impact on the income of the regulated electric operations, as the effects were offset by the establishment of regulatory assets and liabilities pursuant to SFAS No. 71. For obligations related to other operations, a net-of-tax cumulative effect adjustment of approximately $4 million was recorded in the fourth quarter of 2005 as a reduction in earnings (see Note 1).

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

The pro forma effects of adopting FIN 47, including the impact on the balance sheet, net income and related basic and diluted earnings per share, are not presented due to the immaterial impact.

The asset retirement obligation is adjusted each period for any liabilities incurred or settled during the period, accretion expense and any revisions made to the estimated cash flows.

Reconciliation of Asset Retirement Obligation Liability

	Years Ended December 31,	
	2006	2005
	(in millions)	
Balance as of January 1,	$2,058	$1,926
Liabilities incurred due to new acquisitions[a]	59	—
Liabilities settled	(7)	(46)
Accretion expense	143	131
Revisions in estimated cash flows	48	12
Adoption of FIN 47	—	35
Balance as of December 31,	$2,301	$2,058

(a) Primarily represents Duke Energy's acquisition of Cinergy in April 2006.

Accretion expense for the years ended December 31, 2006 and 2005 included approximately $140 million and $130 million, respectively, related to Duke Energy's regulated electric operations which has been deferred as regulatory assets and liabilities in accordance with SFAS No. 71, as discussed above. The fair value of assets legally restricted for the purpose of settling asset retirement obligations associated with nuclear decommissioning was $1,421 million as of December 31, 2006 and $1,194 million as of December 31, 2005.

Nuclear Decommissioning Costs. Pursuant to an order issued by the NCUC on February 5, 2004, Duke Energy was required to contribute amounts reserved for non-contaminated costs of decommissioning to the NDTF over a ten-year period. In April 2004, Duke Energy contributed its entire reserve of $262 million in cash to the NDTF. This contribution is presented in the Consolidated Statements of Cash Flows in Purchases of Available-For-Sale Securities within Cash Flows from Investing Activities.

In 2005, the NCUC and PSCSC approved a $48 million annual amount for contributions and expense levels for decommissioning. In each of the years ended December 31, 2006 and 2005, Duke Energy expensed approximately $48 million and contributed cash of approximately $48 to the NDTF for decommissioning costs. These amounts are presented in the Consolidated Statements of Cash Flows in Purchases of Available-For-Sale Securities within Cash Flows from Investing Activities. In both 2006 and 2005, $48 million was contributed entirely to the funds reserved for contaminated costs. Contributions were discontinued to the funds reserved for non-contaminated costs since the current estimates indicate existing funds to be sufficient to cover projected future costs. The balance of the external funds was $1,775 million as of December 31, 2006 and $1,504 million as of December 31, 2005. These amounts are reflected in the Consolidated Balance Sheets as Nuclear Decommissioning Trust Funds (asset).

Estimated site-specific nuclear decommissioning costs, including the cost of decommissioning plant components not subject to radioactive contamination, total approximately $2.3 billion in 2003 dollars, based on a decommissioning study completed in 2004. This includes costs related to Duke Energy's 12.5% ownership in the Catawba Nuclear Station. The other joint owners of the Catawba Nuclear Station are responsible for decommissioning costs related to their ownership interests in the station. Both the NCUC and the PSCSC have allowed Duke Energy to recover estimated decommissioning costs through retail rates over the expected remaining service periods of Duke Energy's nuclear stations. Management believes that the decommissioning costs being recovered through rates, when coupled with expected fund earnings, are sufficient to provide for the cost of decommissioning.

The operating licenses for Duke Energy's nuclear units are subject to extension. In December 2003, Duke Energy was granted renewed operating licenses for the Catawba and McGuire Nuclear Stations until 2041 and 2043 (license expirations vary by nuclear unit). In 2000, Duke Energy was granted a license renewal for the Oconee Nuclear Station until 2033 and 2034 (license expirations vary by nuclear unit).

Current Operating Licenses for Duke Energy's Nuclear Units

Unit	Expiration Year
McGuire 1	2041
McGuire 2	2043
Catawba 1	2043
Catawba 2	2043
Oconee 1 and 2	2033
Oconee 3	2034

A provision in the Energy Policy Act of 1992 established a fund for the decontamination and decommissioning of the DOE's uranium enrichment plants (the D&D Fund). Licensees are subject to an annual assessment for 15 years based on their pro rata share of past enrichment services. The annual assessment is recorded in the Consolidated Statements of Operations as Fuel Used in Electric Generation and Purchased Power. Duke Energy has paid $152 million into the D&D Fund, including $12 million during 2006 and $11 million during each of 2005 and 2004. There is no remaining liability and regulatory assets as of December 31, 2006. The liability and regulatory assets of $12 million as of December 31, 2005 are reflected in the Consolidated Balance Sheets as Deferred Credits and Other Liabilities, and Regulatory Assets and Deferred Debits, respectively.

8. Risk Management and Hedging Activities, Credit Risk, and Financial Instruments

Duke Energy is exposed to the impact of market fluctuations in the prices of electricity, coal, natural gas and other energy-related products marketed and purchased as a result of its ownership of energy related assets. Exposure to interest rate risk exists as a result of the issuance of variable and fixed rate debt and commercial paper. Duke Energy is exposed to foreign currency risk from investments in international affiliate businesses owned and operated in foreign countries and from certain commodity-related transactions within domestic operations. Duke Energy employs established policies and procedures to manage its risks associated with these market fluctuations using various commodity and financial derivative instruments, including swaps, futures, forwards, options and swaptions.

Duke Energy's Derivative Portfolio Carrying Value as of December 31, 2006

Asset/(Liability)	Maturity in 2007	Maturity in 2008	Maturity in 2009	Maturity in 2010 and Thereafter	Total Carrying Value
			(in millions)		
Hedging	$ 4	$ —	$ 17	$ (8)	$ 13
Trading	2	—	—	—	2
Undesignated	(33)	(5)	2	4	(32)
Total	$(27)	$ (5)	$ 19	$ (4)	$ (17)

The amounts in the table above represent the combination of amounts presented as assets and (liabilities) for unrealized gains and losses on mark-to-market and hedging transactions on Duke Energy's Consolidated Balance Sheets, excluding approximately $39 million of derivative assets and $39 million of derivative liabilities presented as assets and liabilities held for sale at December 31, 2006.

During the third quarter of 2005, Duke Energy's Board of Directors authorized and directed management to execute the sale or disposition of substantially all of DENA's remaining assets and contracts outside the Midwestern United States, approximately 6,100 megawatts of power generation, and certain contractual positions related to the Midwestern assets (see Note 13). As a result, Duke Energy recognized a pre-tax loss of approximately $1.9 billion in the third quarter of 2005 for the disqualification of its power and gas forward sales contracts previously designated under the normal purchases normal sales exception. This loss was partially offset by the recognition of a pre-tax gain of approximately $1.2 billion for the discontinuance of hedge accounting for natural gas and power cash flow hedges. Duke Energy retained the Midwestern generation assets of DENA, representing approximately 3,600 megawatts of power generation, and combined the assets with Cinergy's commercial operations subsequent to the merger with Cinergy on April 3, 2006 (see Note 1 and Note 2 for further details on the completed Cinergy merger). Derivative activity associated with these combined assets is reported in Commercial Power for segment reporting purposes for all periods presented.

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

As a result of the transfer of 19.7% interest in DEFS to ConocoPhillips and the third quarter 2005 deconsolidation of its investment in DEFS (see Note 2), Duke Energy discontinued hedge accounting for certain contracts held by Duke Energy related to Field Services' commodity price risk, which were previously accounted for as cash flow hedges. These contracts were originally entered into as hedges of forecasted future sales by Field Services, and have been retained as undesignated derivatives. Since discontinuance of hedge accounting, these contracts have been marked-to-market in the Consolidated Statements of Operations. As a result, approximately $19 million and $314 million of realized and unrealized pre-tax losses related to these contracts were recognized in earnings by Duke Energy for the years ended December 31, 2006 and December 31, 2005, respectively. All the 2006 charges have been classified in the accompanying Consolidated Statements of Operations as a component of Other Income and Expenses. The 2005 charges were classified in the accompanying Consolidated Statements of Operations for the year ended as follows: upon the discontinuance of hedge accounting approximately $120 million of pre-tax losses were recognized as a component of Impairments and Other Charges while approximately $130 million of losses recognized subsequent to the discontinuance of hedge accounting prior to the deconsolidation of DEFS were recognized as a component of Non-Regulated Electric, Natural Gas, Natural Gas Liquids, and Other Revenues and $64 million of losses recognized subsequent to discontinuance of hedge accounting after the deconsolidation of DEFS were recognized as a component of Other Income and Expenses. Cash settlements on these contracts since the deconsolidation of DEFS on July 1, 2005 of approximately $163 million and $133 million are classified as a component of net cash used in investing activities in the accompanying Consolidated Statements of Cash Flows for the years ended December 31, 2006 and December 31, 2005, respectively.

Commodity Cash Flow Hedges. Some Duke Energy subsidiaries are exposed to market fluctuations in the prices of various commodities related to their ongoing power generating and natural gas gathering, distribution, processing and marketing activities. Duke Energy closely monitors the potential impacts of commodity price changes and, where appropriate, enters into contracts to protect margins for a portion of future sales and generation revenues and fuel expenses. Duke Energy uses commodity instruments, such as swaps, futures, forwards and options, as cash flow hedges for electricity, natural gas and natural gas liquid transactions. Duke Energy is hedging exposures to the price variability of these commodities for a maximum of 1 year.

The ineffective portion of commodity cash flow hedges resulted in a pre-tax gain of $5 million in 2006 and is reported primarily in Non-regulated electric, natural gas, natural gas liquids, and other in the Consolidated Statements of Operations, a pre-tax loss of $12 million in 2005 and a pre-tax gain of $3 million in 2004, both reported primarily in (Loss) Income From Discontinued Operations, net of tax in the Consolidated Statements of Operations. The amount recognized for transactions that no longer qualified as cash flow hedges, which is classified in (Loss) Income From Discontinued Operations, net of tax in the Consolidated Statements of Operations, was a loss of approximately $67 million in 2006, a gain of approximately $1.2 billion in 2005 and was not material in 2004.

As of December 31, 2006, $2 million of pre-tax deferred net gains on derivative instruments related to commodity cash flow hedges were accumulated on the Consolidated Balance Sheets in a separate component of stockholders' equity, in AOCI, and are expected to be recognized in earnings during the next twelve months as the hedged transactions occur. However, due to the volatility of the commodities markets, the corresponding value in AOCI will likely change prior to its reclassification into earnings.

Commodity Fair Value Hedges. Some Duke Energy subsidiaries are exposed to changes in the fair value of some unrecognized firm commitments to sell generated power or natural gas due to market fluctuations in the underlying commodity prices. Duke Energy actively evaluates changes in the fair value of such unrecognized firm commitments due to commodity price changes and, where appropriate, uses various instruments to hedge its market risk. These commodity instruments, such as swaps, futures and forwards, serve as fair value hedges for the firm commitments associated with generated power. The ineffective portion of commodity fair value hedges resulted in a pre-tax gain of $7 million in 2006, a pre-tax loss of $4 million in 2005 and was not material in 2004, and is reported primarily in (Loss) Income From Discontinued Operations, net of tax on the Consolidated Statements of Operations.

Normal Purchases and Normal Sales Exception. Duke Energy has applied the normal purchases and normal sales scope exception, as provided in SFAS No. 133, interpreted by Derivative Implementation Group Issue C15, "Scope Exceptions: Normal Purchases and Normal Sales Exception for Option-Type Contracts and Forward Contracts in Electricity," and amended by SFAS No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities," to certain contracts involving the purchase and sale of electricity at fixed prices in future periods. These contracts, which relate primarily to the delivery of electricity over the next 8 years, are not included in the table above. As discussed above, during 2005, Duke Energy recognized a pre-tax loss of approximately $1.9 billion for the disqualification of its power and gas forward sales contracts.

Certain forward power contracts related to DENA's Southeast Plants and the deferred plants had been primarily designated as normal purchases and sales in accordance with SFAS No. 133. In addition, certain forward gas contracts related to the long-lived assets had been designated as cash flow hedges in accordance with SFAS No. 133. As a result of the change in management intent for the long- lived assets, the related forward power and gas contracts were de-designated as normal purchases and sales and hedges. The amount recognized for transactions that no longer qualified as hedged firm commitments was not material in 2006 and 2004.

Interest Rate (Fair Value or Cash Flow) Hedges. Changes in interest rates expose Duke Energy to risk as a result of its issuance of variable and fixed rate debt and commercial paper. Duke Energy manages its interest rate exposure by limiting its variable-rate exposures to percentages of total capitalization and by monitoring the effects of market changes in interest rates. Duke Energy also enters into financial derivative instruments, including, but not limited to, interest rate swaps, swaptions and U.S. Treasury lock agreements to manage and mitigate interest rate risk exposure. Duke Energy's existing interest rate derivative instruments and related ineffectiveness were not material to its consolidated results of operations, cash flows or financial position in 2006, 2005, and 2004.

Foreign Currency (Fair Value, Net Investment or Cash Flow) Hedges. Duke Energy is exposed to foreign currency risk from investments in international affiliate businesses owned and operated in foreign countries and from certain commodity-related transactions within domestic operations. To mitigate risks associated with foreign currency fluctuations, contracts may be denominated in or indexed to the U.S. dollar and/or local inflation rates, or investments may be naturally hedged through debt denominated or issued in the foreign currency. Duke Energy may also use foreign currency derivatives, where possible, to manage its risk related to foreign currency fluctuations. There was no recognition, a net loss of $1 million and a net loss of $43 million included in the cumulative translation adjustment for hedges of net investments in foreign operations, during 2006, 2005, and 2004, respectively. To monitor its currency exchange rate risks, Duke Energy uses sensitivity analysis, which measures the impact of devaluation of foreign currencies.

During the first quarter of 2005, Duke Energy settled certain hedges which were documented and designated as net investment hedges of the investment in Westcoast Energy, Inc. (Westcoast) on their scheduled maturity and paid approximately $162 million. These settlements are classified as a component of net cash used in investing activities in the accompanying Consolidated Statements of Cash Flows. Losses recognized on this net investment hedge have been classified in AOCI as a component of foreign currency adjustments and will not be recognized in earnings unless the complete or substantially complete liquidation of Duke Energy's investment in Westcoast occurs.

Other Derivative Contracts. *Trading.* Duke Energy has been exposed to the impact of market fluctuations in the prices of natural gas, electricity and other energy-related products marketed and purchased as a result of proprietary trading activities. During 2003, Duke Energy prospectively discontinued proprietary trading. As a result of the Cinergy merger, Duke Energy acquired natural gas and power marketing and trading operations, conducted primarily through CMT, the results of which have been reflected in Income (Loss) from Discontinued Operations, net of tax, from the date of the Cinergy acquisition to the date of sale. In October 2006, the CMT sale transaction was completed and Duke Energy entered into a series of Total Return Swaps (TRS) with Fortis (see Note 13). As of December 31, 2006, the remaining CMT trading contract assets and liabilities and offsetting TRS were classified as Assets Held for Sale in the Consolidated Balance Sheets.

Undesignated. In addition, Duke Energy uses derivative contracts to manage the market risk exposures that arise from energy supply, structured origination, marketing, risk management, and commercial optimization services to large energy customers, energy aggregators and other wholesale companies, and to manage interest rate and foreign currency exposures. This category includes changes in fair value for derivatives that no longer qualify for the normal purchase and normal sales scope exception and disqualified hedge contracts, unless the derivative contract is subsequently re-designated as a hedge. The contracts in this category as of December 31, 2006 are primarily associated with forward power sales and coal purchases for the Commercial Power operations and remaining DENA exit activity announced in 2005 (see Note 13). As of December 31, 2005, this category primarily included disqualified hedges related to the DENA Southeast Plants, hedges related to the partially completed plants which were disqualified in 2003 and certain contracts held by Duke Energy related to Field Services commodity price risk. Duke Energy's exposure to price risk is influenced by a number of factors, including contract size, length, market liquidity, location and unique or specific contract terms.

In connection with the Barclays Bank PLC (Barclays) transaction discussed in Note 13, Duke Energy entered into a series of TRS with Barclays, which are accounted for as mark-to-market derivatives. The TRS offsets the net fair value of the contracts being sold to Barclays. The fair value of the TRS as of December 31, 2006 is an asset of approximately $56 million, which offsets the net fair value of the underlying contracts, which is a liability of approximately $56 million. The TRS will be cancelled as the underlying contracts are transferred to Barclays.

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

Credit Risk. Duke Energy's principal customers for power and natural gas marketing and transportation services are industrial end-users, marketers, local distribution companies and utilities located throughout the U.S., Canada and Latin America. Duke Energy has concentrations of receivables from natural gas and electric utilities and their affiliates, as well as industrial customers and marketers throughout these regions. These concentrations of customers may affect Duke Energy's overall credit risk in that risk factors can negatively impact the credit quality of the entire sector. Where exposed to credit risk, Duke Energy analyzes the counterparties' financial condition prior to entering into an agreement, establishes credit limits and monitors the appropriateness of those limits on an ongoing basis.

Duke Energy's industry has historically operated under negotiated credit lines for physical delivery contracts. Duke Energy frequently uses master collateral agreements to mitigate certain credit exposures, primarily in its trading and marketing and risk management operations. The collateral agreements provide for a counterparty to post cash or letters of credit to the exposed party for exposure in excess of an established threshold. The threshold amount represents an unsecured credit limit, determined in accordance with the corporate credit policy. Collateral agreements also provide that the inability to post collateral is sufficient cause to terminate contracts and liquidate all positions.

Duke Energy also obtains cash or letters of credit from customers to provide credit support outside of collateral agreements, where appropriate, based on its financial analysis of the customer and the regulatory or contractual terms and conditions applicable to each transaction.

Collateral amounts held or posted may be fixed or may vary depending on the terms of the collateral agreement and the nature of the underlying exposure and generally cover trading, normal purchases and normal sales, hedging contracts, and optimization contracts outstanding. Duke Energy may be required to return certain held collateral and post additional collateral should price movements adversely impact the value of open contracts or positions. In many cases, Duke Energy's and its counterparties' publicly disclosed credit ratings impact the amounts of additional collateral to be posted. Likewise, downgrades in credit ratings of counterparties could require counterparties to post additional collateral to Duke Energy and its affiliates.

The change in market value of New York Mercantile Exchange (NYMEX)-traded futures and options contracts requires daily cash settlement in margin accounts with brokers.

Included in Other Current Assets in the Consolidated Balance Sheets as of December 31, 2006 and December 31, 2005 are collateral assets of approximately $92 million and $1,279 million, respectively, which represents cash collateral posted by Duke Energy with other third parties. This decrease in cash collateral posted by Duke Energy is primarily due the sale and wind-down of trading operations. Included in Other Current Liabilities and Other Deferred Credits and Other Liabilities in the Consolidated Balance Sheets as of December 31, 2006 and December 31, 2005 are collateral liabilities of approximately $239 million and $664 million, respectively, which represents cash collateral posted by other third parties to Duke Energy. In connection with the sale to Barclays of contracts related to DENA's energy marketing and management activities, Barclays provided DENA cash equal to the net cash collateral posted by DENA under the contracts. Net cash collateral received by Duke Energy from Barclays in January 2006 was approximately $540 million based on current market prices of the contracts (see Note 13).

Financial Instruments. The fair value of financial instruments, excluding derivatives included elsewhere in this Note and in Note 13, is summarized in the following table. Judgment is required in interpreting market data to develop the estimates of fair value. Accordingly, the estimates determined as of December 31, 2006 and 2005, are not necessarily indicative of the amounts Duke Energy could have realized in current markets.

Financial Instruments

	As of December 31,			
	2006		2005	
	Book Value	Approximate Fair Value	Book Value	Approximate Fair Value
	(in millions)			
Long-term debt(a)	$ 19,723	$ 20,765	$ 15,947	$ 17,014
Long-term SFAS 115 securities	1,946	1,946	1,735	1,735

(a) Includes current maturities.

The fair value of cash and cash equivalents, short-term investments, accounts and notes receivable, accounts payable and commercial paper are not materially different from their carrying amounts because of the short-term nature of these instruments or because the stated rates approximate market rates.

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

9. Marketable Securities

Short-term investments. At December 31, 2006 and 2005 Duke Energy had $1,514 million and $632 million, respectively, of short-term investments consisting primarily of highly liquid tax-exempt debt securities. These instruments are classified as available-for-sale securities under SFAS No. 115 as management does not intend to hold them to maturity nor are they bought and sold with the objective of generating profits on short-term differences in price. The carrying value of these instruments approximates their fair value as they contain floating rates of interest. During 2006, Duke Energy purchased approximately $31,521 million and received proceeds on sale of approximately $30,692 million of short-term investments. During 2005, Duke Energy purchased approximately $38,535 million and received proceeds on sale of approximately $38,386 million of short-term investments. During 2004, Duke Energy purchased approximately $63,879 million and received proceeds on sale of approximately $63,323 million of short-term investments. The weighted-average maturity of these debt securities is less than 1 year.

During 2006, Duke Energy's Natural Gas Transmission business unit received shares of stock as consideration for settlement of a customer's transportation contract. The market value of the equity securities, determined by quoted market prices on the date of receipt, of approximately $28 million is reflected in Gains (Losses) on Sales of Other Assets and Other, net in the Consolidated Statements of Operations for the year ended December 31, 2006. Subsequent to receipt, these securities were accounted for under SFAS No. 115 as trading securities. During the year ended December 31, 2006, these securities were sold and an additional gain of approximately $1 million was recognized in Other Income and Expenses, net in the Consolidated Statements of Operations for the year ended December 31, 2006.

During 2006, Duke Energy recognized an approximate $51 million pre-tax gain on the sale of available-for-sale securities that were included in Assets held for sale on the Consolidated Balance Sheets. This gain was recorded as a component of (Loss) Income from Discontinued Operations in Other.

Other Long-term investments. Duke Energy also invests in debt and equity securities that are held in the NDTF (see Note 7 for further information on the nuclear decommissioning trust funds) and the captive insurance investment portfolio that are classified as available-for-sale under SFAS No. 115 and therefore are carried at estimated fair value based on quoted market prices. These investments are classified as long-term as management does not intend to use them in current operations. The NDTF is managed by independent investment managers with discretion to buy, sell and invest pursuant to the objectives set forth by the trust agreement. As of December 31, 2006 Duke Energy's NDTF ($1,775 million and $1,504 million at December 31, 2006 and 2005, respectively) consists of approximately 70% equity securities, 24% debt securities, and 6% cash and cash equivalents with a weighted-average maturity of the debt securities of approximately 13 years. Duke Energy's captive insurance investment portfolio ($171 million and $203 million at December 31, 2006 and 2005, respectively) consists of approximately 88% debt securities and 12% equity securities with a weighted-average maturity of the debt securities of approximately 21 years, as of December 31, 2006. The cost of securities sold is determined using the specific identification method. During 2006, Duke Energy purchased approximately $1,915 million and received proceeds on sales of approximately $1,904 million on other long-term investments. During 2005, Duke Energy purchased approximately $1,782 million and received proceeds on sales of approximately $1,745 million on other long-term investments. During 2004, Duke Energy purchased approximately $2,050 million and received proceeds on sales of approximately $1,775 million on other long-term investments. Most of these purchases and sales relate to the NDTF.

The estimated fair values of short-term and long-term investments classified as available-for-sale are as follows (in millions):

	As of December 31,					
	2006			2005		
	Gross Unrealized Holding Gains	Gross Unrealized Holding Losses	Estimated Fair Value	Gross Unrealized Holding Gains	Gross Unrealized Holding Losses	Estimated Fair Value
Short-term Investments	$ —	$ —	$ 1,514	$ —	$ —	$ 632
Total short-term investments	$ —	$ —	$ 1,514	$ —	$ —	$ 632
Equity Securities	$ 467	$ —	$ 1,268	$ 333	$ —	$ 1,098
Corporate Debt Securities	1	1	85	—	1	61
Municipal Bonds	1	—	236	1	—	203
U S Government Bonds	7	—	159	13	—	230
Other	1	1	198	—	1	143
Total long-term investments	$ 477	$ 2	$ 1,946	$ 347	$ 2	$ 1,735

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

Approximately $13 million and $21 million of losses are excluded from the above table as of December 31, 2006 and 2005, respectively, which relate to available-for-sale securities held in the NDTF. Pursuant to an order from the NCUC, Duke Energy defers as a regulatory asset or regulatory liability all gains and losses associated with investments in the NDTF. As Duke Energy has limited oversight over the day-to-day management of the NDTF investments, all losses during the years ended December 31, 2006 and 2005 related to holdings of the NDTF have been recognized as a regulatory asset.

For the years ended December 31, 2006, 2005, and 2004 gains of approximately $57 million (including $51 million reclassified to (Loss) Income from Discontinued Operations, net of tax), $3 million and $3 million, respectively, were reclassified out of AOCI into earnings.

Duke Energy contributed approximately $48 million in 2006, $48 million in 2005, and $329 million in 2004 to the NDTF. These contributions are presented in Purchases of available-for-sale securities within Cash Flows From Investing Activities on the Consolidated Statements of Cash Flows. At December 31, 2006 and 2005, gross unrealized holding gains related to the NDTF amounted to $472 million and $316 million, respectively.

10. Goodwill and Intangible Assets

Duke Energy evaluates the impairment of goodwill under the guidance of SFAS No. 142. As a result of the annual impairment tests required by SFAS No. 142, no charge for the impairment of goodwill was recorded in 2006 directly related to these tests. As discussed further in Note 2, in April 2006, Duke Energy and Cinergy consummated the previously announced merger, which resulted in Duke Energy recording goodwill and intangible assets of approximately $5.6 billion. The following table shows the components of goodwill at December 31, 2006:

Changes in the Carrying Amount of Goodwill

	Balance December 31, 2005	Acquisitions[a]	Other[b][e]	Balance December 31, 2006
	(in millions)			
U.S. Franchised Electric and Gas	$—	$3,500	$—	$ 3,500
Natural Gas Transmission	3,512	—	11	3,523
Commercial Power	—	1,020	(135)	885
International Energy	256	—	11	267
Crescent[c]	7	—	(7)	—
Total consolidated	$3,775	$4,520	$(120)	$8,175

	Balance December 31, 2004	Acquisitions	Other[d][e]	Balance December 31, 2005
Natural Gas Transmission	$3,416	$—	$96	$3,512
Field Services	480	—	(480)	—
International Energy	245	—	11	256
Crescent	7	—	—	7
Total consolidated	$4,148	$—	$(373)	$3,775

(a) Goodwill recorded as of December 31, 2006 resulting from Duke Energy's merger with Cinergy is $4,385 million.

(b) Primarily relates to foreign currency translation and approximately $135 million of goodwill allocated to the disposition of CMT (see Note 13).

(c) Reduction in goodwill at December 31, 2006 reflects the deconsolidation of Crescent in September 2006 (see Note 2).

(d) As a result of the deconsolidation of DEFS in July 2005 goodwill decreased by a net amount of $462 million, which includes the effects of an $18 million transfer of goodwill between Field Services and Natural Gas Transmission as a result of the transfer of Canadian assets in connection with the DEFS disposition transaction (see Note 2).

(e) Except as noted in (b), (c) and (d), other amounts consist primarily of foreign currency translation.

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

Intangible Assets

In April 2006, in connection with the merger with Cinergy, Duke Energy recorded gross intangible assets of approximately $1,091 million, primarily relating to approximately $712 million of emission allowances, approximately $295 million of gas, coal and power contracts and approximately $84 million of other intangible assets.

The carrying amount and accumulated amortization of intangible assets as of December 31, 2006 and December 31, 2005 are as follows:

	December 31, 2006	December 31, 2005	Weighted Average Life
		(in millions)	
Emission allowances	$ 587	$ 24	(a)
Gas, coal and power contracts	322	23	(b)
Other	57	23	25
Total gross carrying amount	966	70	
Accumulated amortization—gas, coal and power contracts	(56)	(1)	
Accumulated amortization—other	(5)	(4)	
Total accumulated amortization	(61)	(5)	
Total intangible assets, net	$ 905	$ 65	

(a) Emission allowances do not have a contractual term or expiration date.

(b) Of this balance, as of December 31, 2006, approximately $115 million will be amortized on a consumption basis and does not have a definitive life, approximately $155 million will be amortized on a straight line basis over 20 years, and the remaining balance of approximately $52 million will be amortized on a straight line basis over a weighted average life of approximately 14 years.

Emission allowances sold or consumed during the years ended December 31, 2006, 2005 and 2004 were $428 million, $8 million and $6 million, respectively.

Amortization expense for intangible assets for the years ended December 31, 2006, 2005 and 2004 was approximately $48 million, $1 million and $1 million, respectively.

The table below shows the expected amortization expense for the next five years for intangible assets as of December 31, 2006. The expected amortization expense includes estimates of emission allowances consumption and estimates of consumption of commodities such as gas and coal under existing contracts. The amortization amounts discussed below are estimates. Actual amounts may differ from these estimates due to such factors as changes in consumption patterns, sales or impairments of emission allowances or other intangible assets, additional intangible acquisitions and other events.

	2007	2008	2009	2010	2011
			(in millions)		
Amortization expense	$391	$167	$143	$102	$ 87

In April 2006, Duke Energy recorded an intangible liability in connection with the merger with Cinergy amounting to approximately $113 million associated with the MBSSO in Ohio that will be recognized in earnings over the remaining regulatory period, which ends on December 31, 2008. The carrying amount of this intangible liability was approximately $95 million at December 31, 2006. Amortization expense related to the MBSSO is estimated to amount to approximately $27 million of income in 2007 and $68 million of income in 2008. Duke Energy also recorded approximately $56 million of intangible liabilities associated with other power sale contracts in connection with the merger with Cinergy. The carrying amount of this intangible liability was approximately $39 million at December 31, 2006. This balance will be amortized to income as follows: approximately $17 million in 2007, approximately $6 million in each of the years 2008 through 2010, and approximately $4 million in 2011.

11. Investments in Unconsolidated Affiliates and Related Party Transactions

Investments in domestic and international affiliates that are not controlled by Duke Energy, but over which it has significant influence, are accounted for using the equity method. Duke Energy received distributions of $893 million in 2006 from those investments. Of these distributions, $741 million are included in Other, assets within Cash Flows from Operating Activities on the accompanying Consolidated

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

Statements of Cash Flows and $152 million are included in Distributions from Equity Investments within Cash Flows from Investing Activities on the accompanying Consolidated Statements of Cash Flows. Duke Energy received distributions of $856 million in 2005 Of these distributions, $473 million are included in Other, assets within Cash Flows from Operating Activities on the accompanying Consolidated Statements of Cash Flows and $383 million are included in Distributions from Equity Investments within Cash Flows from Investing Activities on the accompanying Consolidated Statements of Cash Flows Duke Energy received distributions of $139 million in 2004, which are included in Other, assets within Cash Flows from Operating Activities on the accompanying Consolidated Statements of Cash Flows Duke Energy's share of net earnings from these unconsolidated affiliates is reflected in the Consolidated Statements of Operations as Equity in Earnings of Unconsolidated Affiliates. (See Note 2 for 2006 dispositions.)

As of December 31, 2006 and 2005, the carrying amount of investments in affiliates approximated the amount of underlying equity in net assets

Natural Gas Transmission. As of December 31, 2006, investments primarily included a 50% interest in Gulfstream Natural Gas System, LLC (Gulfstream). Gulfstream is an interstate natural gas pipeline that extends from Mississippi and Alabama across the Gulf of Mexico to Florida. Although Duke Energy owns a significant portion of Gulfstream, it is not consolidated as Duke Energy does not hold a majority of voting control or have the ability to exercise control over Gulfstream.

Field Services. In July 2005, Duke Energy completed the transfer of a 19.7% interest in DEFS to ConocoPhillips, Duke Energy's co-equity owner in DEFS, which reduced Duke Energy's ownership interest in DEFS from 69.7% to 50% (the DEFS disposition transactions) and resulted in Duke Energy and ConocoPhillips becoming equal 50% owners in DEFS. As a result of the DEFS disposition transaction, Duke Energy deconsolidated its investment in DEFS which has subsequently been accounted for as an investment utilizing the equity method of accounting (see Note 2). Additionally, in February 2005, DEFS sold its wholly owned subsidiary TEPPCO GP, which is the general partner of TEPPCO LP, for approximately $1.1 billion and Duke Energy sold its limited partner interest in TEPPCO LP for approximately $100 million, in each case to Enterprise GP Holdings LP, an unrelated third party. These transactions resulted in pre-tax gains of approximately $1.8 billion. For the three months ended March 31, 2005, TEPPCO LP had operating revenues of approximately $1,524 million, operating expenses of approximately $1,463 million, operating income of approximately $61.2 million, income from continuing operations of approximately $46.3 million, and net income of approximately $47.4 million.

Commercial Power. As of December 31, 2006, investments primarily included a 50% interest in South Houston Green Power. L.P (Green Power) Green Power is a cogeneration facility containing three combustion turbines in Texas City, Texas. Although Duke Energy owns a significant portion of Green Power, it is not consolidated as Duke Energy does not hold a majority voting control or have the ability to exercise control over Green Power.

International Energy. As of December 31, 2006, investments primarily included a 25% indirect interest in NMC, which owns and operates a methanol and MTBE business in Jubail, Saudi Arabia International Energy also has a 50% ownership in Campeche, a natural gas compression facility in the Cantarell oil field in the Gulf of Mexico and a 25% indirect interest in Attiki, a natural gas distributor in Athens, Greece.

Campeche project revenues are generated from the gas compression services agreement (GCSA) with the Mexican national oil company (PEMEX). The original five year GCSA expired in November 2006 and a nine month extension was executed in October 2006. The facility ownership will transfer to PEMEX in August 2007. See Note 12 for a discussion of the impairment recognized on the Campeche investment.

Crescent. In September 2006, Duke Energy deconsolidated its investment in Crescent JV as a result of a reduction in ownership and subsequently has accounted for the investment using the equity method of accounting.

Other. As of December 31, 2006 investments primarily includes Cinergy's telecom investments As of December 31, 2005, investments primarily included a 50% interest in Southwest Power Partners, LLC. Southwest Power Partners, LLC is a gas-fired combined-cycle facility (Griffith Energy) in Arizona that serves markets in Arizona, Nevada and California. Although Duke Energy owns a significant portion of this investment, it is not consolidated as it does not hold a majority of voting control or have the ability to exercise control over this investment. Southwest Power Partners, LLC was included in DENA's Western United States generation assets that were sold to LS Power during 2006 (see Note 13). As a result, the investment was classified as Assets Held for Sale in the Consolidated Balance Sheets as of December 31, 2005 and earnings and losses from this investment are classified as (Loss) Income from Discontinued Operations, net of tax in the accompanying Consolidated Statements of Operations.

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

Investments in Unconsolidated Affiliates

	As of:					
	December 31, 2006			December 31, 2005		
	Domestic	International	Total	Domestic	International	Total
	(in millions)					
U.S. Franchised Electric and Gas	$ 2	$ —	$ 2	$ 2	$ —	$ 2
Natural Gas Transmission	434	18	452	428	20	448
Field Services[(a)]	1,166	—	1,166	1,290	—	1,290
Commercial Power	223	—	223	—	—	—
International Energy	—	165	165	—	155	155
Crescent[(b)]	180	—	180	17	—	17
Other	104	13	117	14	7	21
Total	$ 2,109	$ 196	$ 2,305	$ 1,751	$ 182	$1,933

(a) Includes Duke Energy's 50 percent interest in DEFS subsequent to deconsolidation of DEFS on July 1, 2005.

(b) Includes Duke Energy's effective 50 percent interest in Crescent subsequent to deconsolidation of Crescent during September 2006

Equity in Earnings of Unconsolidated Affiliates

	For the Years Ended:								
	December 31, 2006			December 31, 2005			December 31, 2004		
	Domestic	International	Total	Domestic	International	Total	Domestic	International	Total
	(in millions)								
U.S. Franchised Electric and Gas	$ (2)	$ —	$ (2)	$ —	$ —	$ —	$ —	$ —	$ —
Natural Gas Transmission	33	2	35	42	5	47	26	4	30
Field Services[(a)]	574	—	574	308	—	308	60	—	60
Commercial Power	21	—	21	—	—	—	—	—	—
International Energy	—	80	80	—	114	114	—	51	51
Crescent[(b)]	23	—	23	(1)	—	(1)	3	—	3
Other[(c)]	(2)	3	1	11	—	11	16	1	17
Total	$647	$ 85	$732	$360	$ 119	$479	$105	$ 56	$ 161

(a) Includes Duke Energy's 50 percent equity in earnings of DEFS subsequent to deconsolidation on July 1, 2005

(b) Includes approximately $15 million for the year ended December 31, 2006 that represents Duke Energy's effective 50% interest in Crescent earnings subsequent to deconsolidation of Crescent in September 2006.

(c) Includes equity investments at the corporate level.

Summarized Combined Financial Information of Unconsolidated Affiliates

As of December 31,

	2006	2005
	(in millions)	
Balance Sheet[a]		
Current assets	$ 3,656	$ 3,414
Non-current assets	10,848	7,744
Current liabilities	(3,354)	(3,395)
Non-current liabilities	(5,155)	(3,237)
Net assets	$ 5,995	$ 4,526

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

	For the Years Ended December 31,		
	2006	2005	2004
	(in millions)		
Income Statement[(a)]			
Operating revenues	$14,259	$8,830	$7,326
Operating expenses	12,365	7,683	6,872
Net income	1,657	1,075	415

(a) Amounts include DEFS and Crescent for the respective periods subsequent to deconsolidation.

Related Party Transactions. Outstanding notes receivable from unconsolidated affiliates were $226 million as of December 31, 2006 and $50 million as of December 31, 2005. Amounts are included in Notes Receivable on the Consolidated Balance Sheets. The balance outstanding as of December 31, 2006 represents International Energy's $16 million note receivable from the Campeche project, a 50% owned joint venture, and Duke Energy Ohio and Duke Energy Indiana's $210 million note receivable from Cinergy Receivables Company LLC (Cinergy Receivables) (see Note 23). The outstanding notes receivable had interest rates approximating current market rates.

International Energy loaned money to Campeche to assist in the costs to build. International Energy received principal and interest payments of approximately $11 million, $5 million and $7 million from Campeche, a 50% owned DEI affiliate, during 2006, 2005 and 2004, respectively.

Duke Energy Ohio and Duke Energy Indiana sell their receivables to Cinergy Receivables. During 2006 (subsequent to the closing of the Cinergy merger in April 2006), Duke Energy Ohio and Duke Energy Indiana collectively sold approximately $3.5 billion of receivables to Cinergy Receivables and received approximately $3.5 billion in proceeds from the sales, including the notes receivable (see Note 23).

Natural Gas Transmission has a 50% ownership in two pipeline companies, Gulfstream, an operating pipeline, and Islander East, LLC, a development stage pipeline as well as a 50% ownership in a power plant, McMahon Cogeneration Plant, a cogeneration natural gas fired facility transferred to Natural Gas Transmission from DENA during 2005. Natural Gas Transmission provides certain administrative and other services to the pipeline companies and the power plant. Natural Gas Transmission recorded recoveries of costs from these affiliates of $19 million, $12 million, and $8 million during 2006, 2005, and 2004, respectively. The outstanding receivable from these affiliates was $5 million and $2 million as of December 31, 2006 and 2005, respectively.

In October 2005, Gulfstream issued $500 million aggregate principal amount of 5.56% Senior Notes due 2015 and $350 million aggregate principal amount of 6.19% Senior Notes due 2025. The proceeds were used by Gulfstream to pay off a construction loan and the balance of the proceeds, net of transaction costs, of approximately $620 million was distributed to the partners based upon their ownership percentage (approximately $310 million was received by Natural Gas Transmission and are included in Distributions from Equity Investments within Cash Flows from Investing Activities in the accompanying Consolidated Statements of Cash Flows).

In December 2005, Duke Energy completed a 140 million Canadian dollars initial public offering on its Canadian income trust fund (the Income Fund) and sold 14 million Trust Units at an offering price of 10 Canadian dollars per Trust Unit. In January 2006, a subsequent greenshoe sale of 1.4 million additional Trust Units, pursuant to an overallotment option, were sold at a price of 10 Canadian dollars per Trust Unit. Subsequent to the January 2006 sale of additional Trust Units, Duke Energy held an approximate 58% ownership interest in the businesses of the Income Fund. Proceeds of approximately 14 million Canadian dollars are included in Proceeds from Duke Energy Income Fund within Cash Flows from Financing Activities in the Consolidated Statements of Cash Flows. In September 2006, the Income Fund sold approximately 9 million previously unissued Trust Units at a price of 12.15 Canadian dollars per Trust Unit for total proceeds of 104 million Canadian dollars, net of commissions and expenses of other expenses of issuance, which is included in Proceeds from Duke Energy Income Fund within Cash Flows from Financing Activities in the Consolidated Statements of Cash Flows. The sale of approximately 9 million Trust Units reduced Duke Energy's ownership interest in the businesses of the Income Fund to approximately 46% at December 31, 2006. As a result of the sale of additional Trust Units, Duke Energy recognized an approximate $15 million U.S. Dollar pre-tax SAB No. 51 gain on the sale of subsidiary stock, which is classified in Gain on Sale of Subsidiary Stock on the Consolidated Statements of Operations. The proceeds from the offering plus the draw down of approximately 39 million Canadian dollars on an available credit facility were used by the Income Fund to acquire a 100% interest in Westcoast Gas Services, Inc. There were no deferred taxes recorded as a result of this transaction.

Advance SC LLC, which provides funding for economic development projects, educational initiatives, and other programs, was formed during 2004. U.S. Franchised Electric and Gas made donations of approximately $24 million and $3 million to the nonconsolidated subsidiary in 2006 and 2005, respectively. Additionally, at December 31, 2006, U.S. Franchised Electric and Gas had a trade payable to Advance SC LLC of approximately $8 million.

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

Field Services sells a portion of its residue gas and NGLs to, purchases raw natural gas and other petroleum products from, and provides gathering and transportation services to unconsolidated affiliates (primarily TEPPCO GP, which was sold in February 2005). Total revenues from these affiliates were approximately $98 million for the six months ended June 30, 2005, and $278 million for the year ended December 31, 2004. Total purchases from these affiliates were approximately $77 million for the six months ended June 30, 2005, and $125 million for the year ended December 31, 2004. Total operating expenses were approximately $1 million for the six months ended June 30, 2005, and $4 million for the year ended December 31, 2004. Reductions in revenues and purchases in 2005 as compared to 2004 are principally due to the sale of TEPPCO GP and deconsolidation of DEFS, effective July 1, 2005

In July 2005, DEFS was deconsolidated due to the transfer of a 19.7% interest to ConocoPhillips and has been subsequently accounted for as an equity investment (see Note 2). Duke Energy's 50% of equity in earnings of DEFS for the year ended December 31, 2006 and the period July 1, 2005 through December 31, 2005 was $574 million and $292 million, respectively, and Duke Energy's investment in DEFS as of December 31, 2006 was $1,166 million, which is included in Investments in Unconsolidated Affiliates in the accompanying Consolidated Balance Sheets. For the year ended December 31, 2006, Duke Energy had gas sales to, purchases from, and other operating revenues from affiliates of DEFS of approximately $137 million, $41 million and $12 million, respectively. As of December 31, 2006, Duke Energy had trade receivables from and trade payables to DEFS amounting to approximately $71 million and $56 million, respectively. Between July 1, 2005 and December 31, 2005, Duke Energy had gas sales to, purchases from, and other operating revenues from affiliates of DEFS of approximately $67 million, $65 million and $12 million, respectively. As of December 31, 2005, Duke Energy had trade receivables from and trade payables to DEFS of approximately $18 million and $47 million, respectively. Additionally, Duke Energy received approximately $725 million and $360 million for its share of distributions paid by DEFS in 2006 and 2005, respectively. Duke Energy has recognized an approximate $64 million receivable as of December 31, 2006 due to its share of quarterly tax distributions declared by DEFS in 2006 and paid in 2007, as compared to $90 million in 2005, which was paid in 2006. Of these distributions $573 million and $287 million were included in Other, assets within Cash Flows from Operating Activities for the years ended 2006 and 2005, respectively, and approximately $152 million and $73 million were included in Distributions from Equity Investments within Cash Flows from Investing Activities for the years ended 2006 and 2005, respectively, within the accompanying Consolidated Statements of Cash Flows. Summary financial information for DEFS, which has been accounted for under the equity method since July 1, 2005 is as follows:

	Twelve-months Ended December 31, 2006	Six-months Ended December 31, 2005
	(in millions)	
Operating revenues	$12,335	$ 7,463
Operating expenses	$11,063	$ 6,814
Operating income	$ 1,272	$ 649
Net income	$ 1,139	$ 584

	December 31, 2006	December 31, 2005
	(in millions)	
Current assets	$ 2,129	$ 2,706
Non-current assets	$ 4,767	$ 5,005
Current liabilities	$ 2,177	$ 3,068
Non-current liabilities	$ 2,391	$ 2,038
Minority interest	$ 71	$ 95

As of December 31, 2006, there was an immaterial basis difference between Duke Energy's carrying value of the investment in DEFS and the value of Duke Energy's proportionate share of the underlying net assets in DEFS.

DEFS is a limited liability company which is a pass-through entity for U.S. income tax purposes. DEFS also owns corporations who file their own respective, federal, foreign and state income tax returns and income tax expense related to these corporations is included in the income tax expense of DEFS. Therefore, DEFS' net income does not include income taxes for earnings which are pass-through to the members based upon their ownership percentage and Duke Energy recognizes the tax impacts of its share of DEFS' pass-through earnings in its income tax expense from continuing operations in the accompanying Consolidated Statements of Operations.

In 2005, DEFS formed DCP Midstream Partners, LP (a master limited partnership). DCP Midstream Partners, LP (DCPLP) completed an initial public offering (IPO) transaction in December 2005 that resulted in net proceeds of approximately $210 million. As a result, DEFS has a 42 percent ownership interest in DCPLP, consisting of a 40 percent limited partner ownership interest and a 2 percent gen —

eral partner ownership interest. DEFS' ownership interest in the general partner of DCPLP is 100 percent. The gain on the IPO transaction has been deferred by DEFS until DEFS converts its subordinated units in DCP to common units, which will occur no earlier than December 31, 2008.

An indirect wholly owned subsidiary of Duke Energy contributed all the membership interest in Crescent to a newly-formed joint venture causing Duke Energy to deconsolidate Crescent as of September 7, 2006 (see Note 2). Duke Energy's 50% of equity in earnings of Crescent for the period from September 8, 2006 through December 31, 2006 was $15 million and Duke Energy's investment in Crescent as of December 31, 2006 was $180 million, which is included in Investments in Unconsolidated Affiliates in the accompanying Consolidated Balance Sheets. Summary financial information for Crescent, which has been accounted for under the equity method since September 7, 2006 is as follows:

	September 7 through December 31, 2006
	(in millions)
Operating revenues	$ 179
Operating expenses	$ 152
Operating income	$ 27
Net income	$ 30

	December 31, 2006
	(in millions)
Current assets	$ 151
Non-current assets	$ 1,810
Current liabilities	$ 211
Non-current liabilities	$ 1,414
Minority interest	$ 31

In the normal course of business, Duke Energy's consolidated subsidiaries enter into energy trading contracts or other derivatives with one another. On a separate company basis, each subsidiary accounts for such contracts as if they were transacted with a third party and records the contracts using the MTM Model or the Accrual Model of Accounting, as applicable. In the consolidation process, the effects of these intercompany contracts are eliminated, and not reflected in Duke Energy's Consolidated Financial Statements

Also see Note 2, Note 12, Note 15, Note 18 and Note 23 for additional related party information.

12. Impairments, Severance, and Other Charges

International Energy. In 2006, International Energy recorded a $50 million other-than-temporary impairment charge related to an investment in Campeche, a natural gas compression facility in the Cantarell oil field in the Gulf of Mexico. Campeche project revenues are generated from the GCSA with the PEMEX. The current GCSA expired in November 2006 and a nine month extension was executed in October 2006. In the second quarter of 2006, based on ongoing discussions with PEMEX, it was determined that there was a limited future need for Campeche's gas compression services. Management of International Energy determined that it is probable that the Campeche investment will ultimately be sold or the GCSA will be renewed for a significantly lower rate. An other-than-temporary impairment loss was recorded to reduce the carrying value to management's best estimate of realizable value. The charges consist of a $17 million impairment of the carrying value of the equity method investment, which has been classified within (Losses) Gains on Sales and Impairments of Equity Investments in the Consolidated Statements of Operations for the year ended December 31, 2006, and a $33 million reserve against notes receivable from Campeche, which has been classified within Operations, Maintenance and Other in the Consolidated Statements of Operations for the year ended December 31, 2006. The facility ownership will transfer to PEMEX in August 2007. The carrying value of the note at December 31, 2006 was $16 million, which is management's best estimate of the net realizable value of the note receivable from Campeche

In December 2006, Duke Energy engaged in discussions with a potential buyer of International Energy's assets in Bolivia. Such discussions to sell the assets were subject to a binding agreement between the parties, which was finalized in February 2007, and resulted in the sale of International Energy's 50 percent ownership interest in two hydroelectric power plants near Cochabamba, Bolivia to Eco —

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

nergy International for approximately $20 million. Based upon the agreed upon selling price of the assets, in December 2006 Duke Energy recorded pre-tax impairment charges of approximately $28 million, which was recorded as a component of Impairment and Other Charges on the Consolidated Statements of Operations. The impairment charges reduced the carrying value of the assets to the estimated selling price pursuant to the aforementioned agreement. As a result of the sale, International Energy no longer has any assets in Bolivia.

A $20 million other than temporary impairment in value of the Campeche investment was recognized during the third quarter of 2005 to write down the investment to its estimated fair value. This impairment is classified as a component of (Losses) Gains on Sales and Impairments of Equity Investments in the accompanying Consolidated Statements of Operations.

Field Services. During the year ended December 31, 2005, the Field Services business unit recorded a charge of approximately $120 million due to the reclassification into earnings of pre-tax unrealized losses from AOCI as a result of the discontinuance of certain cash flow hedges entered into hedge Field Services' commodity price risk. See Note 8 for a discussion of the impacts of the DEFS disposition transaction on certain cash flow hedges.

In the third quarter of 2004, Field Services recorded impairments of approximately $22 million related to DEFS operating assets.

Additionally, in the third quarter of 2004, Field Services recorded an impairment of approximately $23 million related to equity method investments at DEFS. The impairment is included in (Losses) Gains on Sales and Impairments of Equity Investments on the Consolidated Statements of Operations. The impairment charge was related to management's assessment of the recoverability of some equity method investments. Field Services determined that these assets, which are located in the Gulf Coast, were impaired; therefore they were written down to fair value. Fair value was determined based on management's best estimates of sales value and/or discounted future cash flow models.

Crescent. In the third quarter of 2005, Crescent recognized pre-tax impairment charges of approximately $16 million related to a residential community near Hilton Head Island, South Carolina, that includes both residential lots and a golf club, to reduce the carrying value of the community to its estimated fair value. This impairment was recognized as a component of Impairments and Other Charges in the accompanying Consolidated Statements of Operations. This community has incurred higher than expected costs and has been impacted by lower than anticipated sales volume. The fair value of the remaining community assets was determined based upon management's estimate of discounted future cash flows generated from the development and sale of the community.

In the fourth quarter of 2004, Crescent recorded impairment charges of approximately $42 million related to two residential developments in Payson, Arizona, the Rim and Chaparral Pines, and one residential development in Austin, Texas, Twin Creeks. The impairment charges were related to long lived assets at the three properties. The developments have suffered from slower than anticipated absorption of available inventory. Fair value of the assets was determined based on management's assessment of current operating results and discounted future cash flow models. Crescent also recorded bad debt charges of $8 million related to notes receivable due from Rim Golf Investor, LLC and Chaparral Pines Investor, LLC. This amount is recorded in Operation, Maintenance and Other on the Consolidated Statements of Operations.

Other. See Note 8 for a discussion of the impacts of the DENA exit plan on certain cash flow hedges

Severance. During the period from the effective date of the Cinergy merger through December 31, 2006, Duke Energy accrued approximately $89 million related to voluntary and involuntary severance as a result of the merger with Cinergy (see Note 2). Additionally, Duke Energy recorded approximately $45 million in severance liabilities related to legacy Cinergy that has been included in goodwill.

As discussed in Note 13, in June 2006, Duke Energy announced it had reached an agreement to sell CMT, as well as associated contracts managed by these companies, to Fortis, a Benelux-based financial services group. As such, results of operations for CMT have been reflected in (Loss) Income from Discontinued Operations, net of tax, from the date of the Cinergy acquisition to the date of sale. The sale of CMT was consummated in October 2006 and Duke Energy did not record any material severance liabilities as a result of the disposal.

During the fourth quarter of 2006, in connection with Duke Energy's spin-off of Spectra Energy, Duke Energy recognized approximately $12 million of severance costs under its ongoing severance plan. Future severance costs under this plan, if any, are not currently estimable.

As discussed further in Note 13, during the third quarter of 2005, the Board of Directors of Duke Energy authorized and directed management to execute the sale or disposition of substantially all of DENA's remaining assets and contracts outside the Midwestern United States and certain contractual positions related to the Midwestern assets. As a result of this exit plan, during the year ended

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

December 31, 2005, DENA recorded a severance accrual of approximately $22 million, under its ongoing severance plan, related to the anticipated involuntary termination of DENA employees. Approximately $2 million of the related pre-tax expense is reflected in Operation, Maintenance and Other and approximately $20 million is reflected in (Loss) Income from Discontinued Operations, net of tax in the accompanying Consolidated Statements of Operations for the year ended December 31, 2005. Additionally, DENA offered certain enhanced severance benefits to employees involuntarily terminated in connection with the DENA disposition plan, which are being recognized over the remaining service period. Approximately $3 million of enhanced severance benefits were accrued during the fourth quarter of 2005. During 2006, Duke Energy reversed approximately $9 million of previously recorded severance amounts due to a change in estimate. As a result of this exit plan, Duke Energy terminated approximately 207 employees through the end of 2006. Management anticipates future severance costs related to this exit plan, which relate to retention costs associated with future services, not included in the following table will not be material.

During 2002, Duke Energy communicated a voluntary and involuntary severance program across all segments to align the business with market conditions during that period. Severance plans related to the program were amended effective August 1, 2004 and applied to individuals notified of layoffs between that date and January 1, 2006.

Severance Reserve	Balance at January 1, 2006	Provision/ Adjustments	Noncash Adjustments	Cash Reductions	Balance at December 31, 2006
			(in millions)		
Natural Gas Transmission	$ 3	$ —	$ —	$ (1)	$ 2
Other(c)	28	146	(11)	(103)	60
Total(a)	$ 31	$ 146	$ (11)	$ (104)	$ 62

	Balance at January 1, 2005	Provision/ Adjustments	Noncash Adjustments	Cash Reductions	Balance at December 31, 2005
U.S. Franchised Electric and Gas	$ 4	$ —	$ (2)	$ (2)	$ —
Natural Gas Transmission	6	1	(1)	(3)	3
Field Services(b)	—	1	(1)	—	—
International Energy	1	—	(1)	—	—
Other(c)	4	26	—	(2)	28
Total(a)	$ 15	$ 28	$ (5)	$ (7)	$ 31

	Balance at January 1, 2004	Provision/ Adjustments	Noncash Adjustments	Cash Reductions	Balance at December 31, 2004
U.S. Franchised Electric and Gas	$ 60	$ —	$ (6)	$ (50)	$ 4
Natural Gas Transmission	29	1	(6)	(18)	6
Field Services(b)	6	1	—	(7)	—
International Energy	6	—	(4)	(1)	1
Other(c)	49	3	(5)	(43)	4
Total(a)	$150	$ 5	$ (21)	$ (119)	$ 15

(a) Substantially all expected severance costs will be applied to the reserves within one year.

(b) Includes minority interest.

(c) Severance expense included in (Loss) Income From Discontinued Operations, net of tax in the Consolidated Statements of Operations was $(9) million, $22 million, and $1 million for 2006, 2005, and 2004, respectively.

13. Discontinued Operations and Assets Held for Sale

The following table summarizes the results classified as (Loss) Income from Discontinued Operations, net of tax, in the accompanying Consolidated Statements of Operations.

Discontinued Operations (in millions)

		Operating Income (Loss)			Net Gain (Loss) on Dispositions			
	Operating Revenues	Pre-tax Operating Income (Loss)	Income Tax Expense (Benefit)	Operating Income (Loss), Net of Tax	Pre-tax Gain (Loss) on Dispositions	Income Tax Expense (Benefit)	Gain (Loss) on Dispositions, Net of Tax	(Loss) Income from Discontinued Operations, Net of Tax
Year Ended December 31, 2006								
Commercial Power	$ 34	$ (7)	$ (7)	$ —	$ 33	$ 50	$ (17)	$ (17)
International Energy	—	(3)	2	(5)	(10)	(3)	(7)	(12)
Other[(a)]	749	(56)	(10)	(46)	(127)	(46)	(81)	(127)
Total consolidated	$ 783	$ (66)	$ (15)	$ (51)	$(104)	$ 1	$ (105)	$ (156)
Year Ended December 31, 2005								
Field Services	$ 4	$ —	$ —	$ —	$ —	$ —	$ —	$ —
International Energy	—	(3)	1	(4)	—	—	—	(4)
Crescent	2	1	—	1	10	4	6	7
Other[(a)]	2,670	(658)	(243)	(415)	(481)	(192)	(289)	(704)
Total consolidated	$2,676	$ (660)	$ (242)	$ (418)	$(471)	$ (188)	$ (283)	$ (701)
Year Ended December 31, 2004								
Field Services	$ 79	$ 3	$ 1	$ 2	$ (17)	$ (6)	$ (11)	$ (9)
International Energy	85	(13)	(1)	(12)	295	22	273	261
Crescent	2	—	—	—	9	4	5	5
Other[(a)]	3,125	20	34	(14)	1	—	1	(13)
Total consolidated	$3,291	$ 10	$ 34	$ (24)	$ 288	$ 20	$ 268	$ 244

(a) *Other includes the results for DENA's discontinued operations, which were previously reported in the DENA segment.*

The following table presents the carrying values of the major classes of assets and associated liabilities held for sale in the accompanying Consolidated Balance Sheets as of December 31, 2006 and 2005. Assets held for sale as of December 31, 2006 primarily relate to Duke Energy Indiana's Wabash River Power Station (see Note 2). Assets held for sale as of December 31, 2005 primarily relate to DENA's assets that were sold to LS Power, as discussed further below.

Summarized Balance Sheet Information for Assets and Associated Liabilities Held for Sale

	December 31, 2006	December 31, 2005
	(in millions)	
Current assets	$ 28	$ 1,528
Investments and other assets	19	2,059
Property, plant and equipment, net	115	1,538
Total assets held for sale	$162	$ 5,125
Current liabilities	$ 26	$ 1,488
Long-term debt	—	61
Deferred credits and other liabilities	18	2,024
Total liabilities associated with assets held for sale	$ 44	$ 3,573

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

Commercial Power

In June 2006, Duke Energy announced it had reached an agreement to sell CMT, as well as certain Duke Energy Ohio trading contracts, to Fortis, a Benelux-based financial services group In October 2006, the sale transaction was completed. Under the purchase and sale agreement, Fortis purchased CMT at a base price of approximately $210 million. In addition, Fortis paid approximately $200 million for the portfolio of contracts and an amount equal to the estimated net working capital associated with these companies at the time of close In October 2006, Duke Energy received total pre-tax cash proceeds of approximately $700 million and recorded an approximate $25 million pre-tax gain on the sale Income tax expense recorded as a result of this transaction relates to the approximate $135 million of goodwill included in assets held for sale that was not deductible for tax purposes, thus creating a taxable gain that was greater than the gain for book purposes. Results of operations for CMT, as well as certain Duke Energy Ohio trading contracts, have been reflected in (Loss) Income from Discontinued Operations, net of tax, from the date of the Cinergy acquisition through the date of sale.

In October 2006, in connection with this transaction, Duke Energy entered into a series of Total Return Swaps (TRS) with Fortis, which are accounted for as mark to market derivatives. The TRS offsets the net fair value of the contracts being sold to Fortis. The TRS will be cancelled for each underlying contracts as each is transferred to Fortis. All economic and credit risk associated with the contracts has been transferred to Fortis as of the date of the sale through the TRS. As of December 31, 2006, approximately 70% of the contracts had been novated by Fortis At December 31, 2006, contracts with a net fair value of approximately $43 million remain in Assets Held for Sale and represent contracts that have yet to be novated by Fortis.

Field Services

In December 2004, based upon management's assessment of the probable disposition of some plant and transportation assets in Wyoming, Field Services wrote down the book value of those assets by $4 million ($3 million net of minority interest) to $10 million, which represented the estimated fair value less cost to sell. The after tax loss and results of operations related to these assets were included in (Loss) Income from Discontinued Operations, net of tax, in the accompanying Consolidated Statements of Operations. In February 2005, these assets were exchanged for certain gathering assets in Oklahoma of equivalent fair value.

In December 2004, Field Services sold gas system and treating plant assets in Southeast New Mexico and South Texas, respectively. Field Services sold these assets for proceeds of approximately $6 million, with the carrying value being approximately equal to the sales price. The after tax loss and related results of operations were included in (Loss) Income from Discontinued Operations, net of tax, in the accompanying Consolidated Statements of Operations.

In September 2004, Field Services recorded a pre-tax impairment charge of approximately $23 million ($16 million net of minority interest) related to management's current assessment of some additional gathering, processing, compression and transportation assets in Wyoming being held for sale. The estimated fair value of these assets less cost to sell was $27 million. The after tax loss and results of operations were included in (Loss) Income from Discontinued Operations, net of tax, in the accompanying Consolidated Statements of Operations In the first quarter of 2005, Field Services sold these assets for proceeds of $28 million, with the carrying value being approximately equal to the sales price.

In February 2004, Field Services sold gas gathering and processing plant assets in West Texas to a third party purchaser for a sales price of approximately $62 million, which approximated these assets' carrying value. The after tax gain and results of operations related to these assets were included in (Loss) Income from Discontinued Operations, net of tax, in the accompanying Consolidated Statements of Operations.

International Energy

In order to eliminate exposure to international markets outside of Latin America and Canada, International Energy decided in 2003 to pursue a possible sale or IPO of International Energy's Asia-Pacific power generation and natural gas transmission business (the Asia-Pacific Business) As a result of this decision, International Energy recorded an after tax loss of $233 million during the fourth quarter of 2003, which represented the excess of the carrying value over the estimated fair value of the business, less estimated costs to sell. In the first quarter of 2004, International Energy determined it was likely that a bid in excess of the originally determined fair value would be accepted and thus recorded a $238 million after tax gain related to International Energy's Asia-Pacific Business The after tax gain was included in (Loss) Income from Discontinued Operations, net of tax, in the accompanying Consolidated Statements of Operations and restored the loss recorded during the fourth quarter of 2003.

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

In the second quarter of 2004, International Energy completed the sale of the Asia-Pacific Business to Alinta Ltd. for a gross sales price of approximately $1.2 billion. This resulted in recording an additional $40 million after tax gain in the second quarter of 2004. The after tax gain was included in (Loss) Income from Discontinued Operations, net of tax, in the accompanying Consolidated Statements of Operations. International Energy received approximately $390 million of cash proceeds, net of approximately $840 million of debt retired (as a non-cash financing activity) as part of the Asia-Pacific Business.

International Energy held a receivable from Norsk Hydro ASA (Norsk) related to the 2003 sale of International Energy's European business. In 2004, International Energy recorded a $14 million ($9 million after tax) allowance against the carrying value of the note based on management's assessment of the probability of not collecting the entire note. In first quarter 2006, based on management's best estimate of recoverability, International Energy recorded an allowance of approximately $19 million ($12 million after tax) against this receivable, which was recorded in (Loss) Income From Discontinued Operations, net of tax in the Consolidated Statements of Operations. During the second quarter of 2006, International Energy and Norsk signed a settlement agreement in which Norsk agreed to pay International Energy approximately $34 million in full settlement of International Energy's receivable. In connection with this settlement, International Energy recorded an approximate $9 million write-up ($5 million after tax) of the receivable through a reduction in the valuation allowance, which was recorded in (Loss) Income From Discontinued Operations, net of tax on the Consolidated Statements of Operations. In July 2006, International Energy received the settlement proceeds.

The operating results related to these operations were included in (Loss) Income from Discontinued Operations, net of tax, in the accompanying Consolidated Statements of Operations.

Crescent

Crescent routinely develops real estate projects and operates those facilities until they are substantially leased and a sales agreement is finalized. In September 2006, Duke Energy deconsolidated its investment in Crescent (see Note 2) and subsequently accounts for its investment in the Crescent JV under the equity method of accounting. Prior to the date of deconsolidation, if Crescent did not retain any significant continuing involvement after the sale, Crescent classified the project as "discontinued operations" as required by SFAS No. 144.

In 2005, Crescent sold three commercial properties resulting in sales proceeds of approximately $44 million. The $6 million after tax gain on these sales was included in (Loss) Income from Discontinued Operations, net of tax, in the accompanying Consolidated Statements of Operations.

In 2004, Crescent sold one multi-family, two residential and two commercial properties resulting in sales proceeds of approximately $52 million. The $5 million after tax gain on these sales was included in (Loss) Income from Discontinued Operations, net of tax, in the accompanying Consolidated Statements of Operations.

Other

During the third quarter of 2005, Duke Energy's Board of Directors authorized and directed management to execute the sale or disposition of substantially all of DENA's remaining assets and contracts outside the Midwestern United States and certain contractual positions related to the Midwestern assets. The DENA assets to be divested include:

- Approximately 6,100 MW of power generation located primarily in the Western and Eastern United States, including all of the commodity contracts (primarily forward gas and power contracts) related to these facilities,
- All remaining commodity contracts related to DENA's Southeastern generation operations, which were substantially disposed of in 2004, and certain commodity contracts related to DENA's Midwestern power generation facilities, and
- Contracts related to DENA's energy marketing and management activities, which include gas storage and transportation, structured power and other contracts.

The results of operations of DENA's Western and Eastern United States generation assets, including related commodity contracts, certain contracts related to DENA's energy marketing and management activities and certain general and administrative costs, are required to be classified as discontinued operations for current and prior periods in the accompanying Consolidated Statements of Operations.

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

Management retained DENA's Midwestern generation assets, consisting of approximately 3,600 MW of power generation, and certain contracts related to the Midwestern generating facilities, as the merger with Cinergy provided a sustainable business model for those assets (see Note 2 for further details on the Cinergy merger) Accordingly, these assets do not qualify for discontinued operations classification and remain in continuing operations as a component of the Commercial Power segment Also transferred to Commercial Power were DENA's Southeastern generation operations, including related commodity contracts, which do not meet the requirements for discontinued operations classification due to Duke Energy's continuing involvement with these operations In addition, management will continue to wind down the limited remaining operations of DETM, the results of which will be reported in Other's continuing operations until the wind down of the operations is complete

In connection with this exit plan, Duke Energy recognized pre-tax losses of approximately $1.1 billion in 2005 in (Loss) Income From Discontinued Operations, net of tax, in the Consolidated Statement of Operations. These losses principally related to:

- The discontinuation of the normal purchase/normal sale exception for certain forward power and gas contracts (an approximate $1.9 billion pre-tax charge)
- The reclassification of approximately $1.2 billion of pre-tax deferred net gains in AOCI for cash flow hedges of forecasted gas purchase and power sale transactions that will no longer occur as a result of the exit plan
- Pre-tax impairments of approximately $0.2 billion to reduce the carrying value of the plants that are expected to be sold to their estimated fair value less cost to sell. Fair value of the assets that are expected to be sold was estimated based upon the signed agreement with LS Power, as discussed below
- Pre-tax losses of approximately $0.4 billion as the result of selling certain gas transportation and structured contracts (as discussed further below), and
- Pre-tax deferred gains in AOCI of approximately $0.2 billion related to the discontinued cash flow hedges of forecasted gas purchase and power sale transactions, which were recognized as the forecasted transactions occurred

As of the September 2005 exit announcement date, management anticipated that additional charges would be incurred related to the exit plan, including termination costs for gas transportation, storage, structured power and other contracts of approximately $600 million to $800 million, which included approximately $40 million to $60 million of severance, retention and other transaction costs (see Note 12). Included in these amounts are the effects of DENA's November 2005 agreement to sell substantially all of its commodity contracts related to the Southeastern generation operations, which were substantially disposed of in 2004, certain commodity contracts related to DENA's Midwestern power generation facilities, and contracts related to DENA's energy marketing and management activities. Excluded from the contracts sold to Barclays are commodity contracts associated with the near-term value of DENA's West and Northeastern generation assets and with remaining gas transportation and structured power contracts. Approximately $700 million has been incurred from the announcement date through December 31, 2006, of which approximately $230 million was incurred during the year ended December 31, 2006, and was recognized in (Loss) Income From Discontinued Operations, net of tax, and approximately $470 million was incurred during the year ended December 31, 2005, approximately $400 million of which was recognized in (Loss) Income From Discontinued Operations, net of tax. As of December 31, 2006 the DENA exit activities are substantially complete and no additional charges are anticipated.

Among other things, the agreement provides that all economic benefits and burdens under the contracts were transferred to Barclays. Cash consideration paid to Barclays amounted to approximately $100 million in 2005 and approximately $600 million in January 2006. Additionally, in January 2006 Barclays provided Duke Energy with cash equal to the net cash collateral posted by DENA under the contracts of approximately $540 million. The novation or assignment of physical power contracts was subject to FERC approval, which was received in January 2006.

In January 2006, Duke Energy signed an agreement to sell to LS Power DENA's entire fleet of power generation assets outside the Midwest, representing approximately 6,100 megawatts of power generation located in the Western and Northeast United States. In May 2006, the transaction with LS Power closed and total proceeds from the sale were approximately $1.56 billion, including certain working capital adjustments. Additional proceeds of up to approximately $40 million were subject to LS Power obtaining certain state regulatory approvals. On July 20, 2006 the Public Utilities Commission of the State of California approved a toll arrangement related to the Moss Landing facility previously sold to LS Power. In August 2006, LS Power made an additional payment to Duke Energy of approximately $40 million, which Duke Energy recorded as an additional gain on the sale of assets.

Notes To Consolidated Financial Statements—(Continued)

In October 2006, Duke Energy recognized an approximate $38 million pre-tax gain on the sale of available-for-sale securities that were included in Assets Held for Sale on the Consolidated Balance Sheets. This gain was recorded as a component of (Loss) Income from Discontinued Operations, net of tax in the Consolidated Statements of Operations.

See Note 3 for a discussion of the impacts of this exit activity on Duke Energy's segment presentation

In the fourth quarter of 2006, the last remaining contract related to DEM expired, which completed Duke Energy's exit from DEM's operations. Accordingly, results of operations for DEM for all periods presented have been reclassified to a component of (Loss) Income From Discontinued Operations, net of tax, on the Consolidated Statements of Operations.

In the first quarter of 2005, Duke Energy's Grays Harbor facility was sold to an affiliate of Invenergy LLC, resulting in a pre-tax gain of approximately $21 million (excludes any potential contingent consideration).

In the third quarter of 2005, Duke Energy completed the sale of Bayside Power L.P. (Bayside) to affiliates of Irving Oil Limited (Irving), under which Irving would purchase Duke Energy's 75% interest in Bayside. The after tax gain on this sale is included in (Loss) Income from Discontinued Operations, net of tax, in the accompanying Consolidated Statements of Operations. Bayside was consolidated with the adoption of FIN 46R on March 31, 2004. Therefore, Bayside's operating results after March 31, 2004 are included in (Loss) Income from Discontinued Operations, net of tax, in the accompanying Consolidated Statements of Operations. Prior operating results are not included in Discontinued Operations, as Bayside was previously accounted for as an equity method investment.

For the year ended December 31, 2004, Duke Energy's discontinued operations also included sales and impairments of merchant power plants located in Washington ("Grays Harbor" plant), Nevada ("Moapa" plant) and New Mexico ("Luna" plant) (collectively, the deferred plants). The deferred plants were a component of DENA's Western United States generation assets that meets the requirements for discontinued operations classification for current and prior periods in the accompanying Consolidated Statements of Operations. Details are as follows:

- The partially completed Moapa facility was sold to Nevada Power Company and resulted in $186 million in net proceeds and a pre-tax gain of approximately $140 million recorded in (Loss) Income from Discontinued Operations, net of tax, in the 2004 Consolidated Statement of Operations

- The partially completed Luna facility was sold to PNM Resources, Tucson Electric Power and Phelps Dodge Corporation. This sale resulted in net proceeds of $40 million and a pre-tax gain of $40 million recorded in (Loss) Income from Discontinued Operations, net of tax, in the 2004 Consolidated Statement of Operations.

- In December 2004, Duke Energy agreed to sell the partially completed Grays Harbor facility to an affiliate of Invenergy LLC and terminated its capital lease associated with the dedicated pipeline which would have transported natural gas to the plant. This termination resulted in a $20 million pre-tax charge recorded in (Loss) Income from Discontinued Operations, net of tax, in the 2004 Consolidated Statement of Operations. As discussed above, in the first quarter of 2005, Grays Harbor was sold

Additionally, during 2004, the Western and Northeast operations had operating losses, which substantially offset the above 2004 gains. During 2004, Duke Energy received approximately $58 million from the sale or collection of all of DCP notes receivable. An immaterial after tax gain related to this transaction was included in (Loss) Income from Discontinued Operations, net of tax, in the accompanying Consolidated Statements of Operations

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

14. Property, Plant and Equipment

	Estimated Useful Life	December 31, 2006	2005
	(Years)	(in millions)	
Land	—	$ 684	$ 571
Plant—Regulated			
Electric generation, distribution and transmission [a]	20 – 125	29,845	18,935
Natural gas transmission and distribution	20 – 82	12,374	10,810
Gathering and processing facilities [a]	20 – 25	2,219	1,570
Other buildings and improvements [a]	16 – 90	613	388
Plant—Unregulated			
Electric generation, distribution and transmission [a]	20 – 125	6,036	3,869
Natural gas transmission and distribution	20 – 82	68	32
Gathering and processing facilities	20 – 25	198	678
Other buildings and improvements [a]	16 – 90	43	27
Nuclear fuel	4	890	890
Equipment [a]	3 – 40	1,098	669
Vehicles	3 – 25	134	125
Construction in process	—	2,257	946
Other [a]	5 – 122	1,871	1,313
Total property, plant and equipment		58,330	40,823
Total accumulated depreciation—regulated [b], [c]		(15,538)	(10,721)
Total accumulated depreciation—unregulated [c]		(1,345)	(902)
Total net property, plant and equipment		$ 41,447	$ 29,200

(a) Includes capitalized leases: $161 million for 2006 and $48 million for 2005.

(b) Includes accumulated amortization of nuclear fuel: $541 million for 2006 and $583 million for 2005.

(c) Includes accumulated amortization of capitalized leases: $28 million for 2006 and $19 million for 2005

Capitalized interest, which includes the interest expense component of AFUDC, amounted to $56 million for 2006, $23 million for 2005, and $18 million for 2004

15. Debt and Credit Facilities

Summary of Debt and Related Terms

	Weighted-Average Rate	Year Due	December 31, 2006	2005
			(in millions)	
Unsecured debt	6.6%	2007 – 2036	$14,504	$12,600
Secured debt	6.5%	2007 – 2024	1,453	1,570
First and refunding mortgage bonds	5.2%	2008 – 2032	1,507	1,214
Capital leases	5.4%	2007 – 2025	94	10
Other debt [a]	4.9%	2007 – 2040	1,875	208
Commercial paper [b]	5.4%		751	383
Fair value hedge carrying value adjustment		2008 – 2032	43	58
Unamortized debt discount and premium, net			(54)	(13)
Total debt [c]			20,173	16,030
Current maturities of long-term debt			(1,605)	(1,400)
Short-term notes payable and commercial paper [d]			(450)	(83)
Total long-term debt [e]			$18,118	$14,547

(a) Includes $1,329 million and $172 million of Duke Energy pollution control bonds as of December 31, 2006 and 2005, respectively. As of December 31, 2006 and 2005, $408 million and $40 million, respectively, was secured by first and refunding mortgage bonds and $344 million and $77 million, respectively, was secured by a letter of credit.

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

(b) Includes $300 million as of both December 31, 2006 and 2005 that was classified as Long-term Debt on the Consolidated Balance Sheets due to the existence of long-term credit facilities which back-stop these commercial paper balances along with Duke Energy's ability and intent to refinance these balances on a long-term basis. The weighted-average days to maturity were 25 days as of December 31, 2006 and 18 days as of December 31, 2005.

(c) As of December 31, 2006, $508 million of debt was denominated in Brazilian Reals and $3,820 million of debt was denominated in Canadian dollars. As of December 31, 2005, $501 million of debt was denominated in Brazilian Reals and $3,917 million of debt was denominated in Canadian dollars.

(d) Weighted-average rates on outstanding short-term notes payable and commercial paper was 5.4% as of December 31, 2006 and 3.3% as of December 31, 2005.

(e) The current and non-current portions of Crescent's long-term debt balances of approximately $2 million and approximately $23 million, respectively, as of December 31, 2005, are no longer included in Duke Energy's consolidated debt balance due to the deconsolidation of Crescent in September 2006.

Unsecured Debt. At December 31, 2006, approximately $629 million of pollution control bonds and approximately $300 million of commercial paper, which are short-term obligations by nature, were classified as long-term debt on the Consolidated Balance Sheets due to Duke Energy's intent and ability to utilize such borrowings as long-term financing. Duke Energy's credit facilities with non-cancelable terms in excess of one year as of the balance sheet date give Duke Energy the ability to refinance these short-term obligations on a long-term basis.

In November 2006, Union Gas issued 4.85% fixed-rate debenture bonds denominated in 125 million Canadian dollars (approximately $108 million U.S. dollar equivalents as of the closing date) due in 2022.

In October 2006, Duke Energy Carolinas issued $150 million in tax-exempt floating rate bonds. The bonds are structured as variable rate demand bonds, subject to weekly remarketing and bear a final maturity of 2031. The initial interest rate was set at 3.72%. The bonds are supported by an irrevocable 3-year direct-pay letter of credit and were issued through the North Carolina Capital Facilities Finance Agency to fund a portion of the environmental capital expenditures at the Marshall and Belews Creek Steam Stations.

In September 2006, prior to the completion of the joint venture transaction of Crescent, as discussed in Note 2, the Crescent JV, Crescent and Crescent's subsidiaries borrowed approximately $1.23 billion principal amount of debt. The net proceeds from the debt issuance of approximately $1.21 billion were recorded as a cash inflow within Financing Activities on the Consolidated Statements of Cash Flows and were distributed to Duke Energy. As a result of Duke Energy's deconsolidation of Crescent effective September 7, 2006, Crescent's outstanding debt balance of $1,298 million was removed from Duke Energy's Consolidated Balance Sheets.

In September 2006, Union Gas Limited (Union Gas) entered into a fixed-rate financing agreement denominated in 165 million Canadian dollars (approximately $148 million in U.S. dollar equivalents as of the issuance date) due in 2036 with an interest rate of 5.46%.

In August 2006, Duke Energy Kentucky issued approximately $77 million principal amount of floating rate tax-exempt notes due August 1, 2027. Proceeds from the issuance were used to refund a like amount of debt on September 1, 2006 then outstanding at Duke Energy Ohio. Approximately $27 million of floating rate debt was swapped to a fixed rate concurrent with closing.

In June 2006, Duke Energy Indiana issued $325 million principal amount of 6.05% senior unsecured notes due June 15, 2016. Proceeds from the issuance were used to repay $325 million of 6.65% First Mortgage Bonds that matured on June 15, 2006.

In November 2005, International Energy issued floating rate debt in Guatemala for $87 million (in USD) and in El Salvador for $75 million (in USD). These debt issuances have variable interest rate terms and mature in 2015.

On September 21, 2005, Union Gas entered into a fixed-rate financing agreement denominated in 200 million Canadian dollars (approximately $171 million in U.S. dollar equivalents as of the issuance date) due in 2016 with an interest rate of 4.64%.

In August 2005, DEI issued project-level debt in Peru, of which $75 million is denominated in U.S. dollars and approximately $34 million (in U.S. dollar equivalents as of the issuance date) is denominated in Peru Nuevos Soles. This debt has terms ranging from four to six years as well as variable or fixed interest rate terms, as applicable.

On March 1, 2005, redemption notices were sent to the bondholders of the $100 million PanEnergy 8.625% bonds due in 2025. These bonds were redeemed on April 15, 2005 at a redemption price of 104.03 or approximately $104 million.

Additionally, Duke Capital remarketed $750 million of its 4.32% senior notes due in 2006, underlying Duke Energy's 8.00% Equity Units on August 11, 2004. As a result of the remarketing, the interest rate on the notes was reset to 4.331%, effective August 16, 2004. Duke Capital subsequently exchanged $400 million of the 4.331% notes for $408 million of 5.668% notes due in 2014. This transaction resulted in an approximate $6 million loss, which was included in Interest Expense in the Consolidated Statements of Operations for the year end December 31, 2004. Proceeds from the remarketed notes were used to purchase U.S. Treasury securities held by the collateral agent and, upon maturity, were used to satisfy the forward stock purchase contract component of the 8% Equity Units in November 2004.

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

Convertible Debt. As of December 31, 2006 and 2005, unsecured debt included $110 million and $742 million, respectively, of 1.75% convertible senior notes due in 2023. These senior notes, which were issued in May 2003, are convertible to Duke Energy common stock at a premium of 40% above the May 1, 2003 closing common stock market price of $16.85 per share. The senior notes outstanding as of December 31, 2006 are potentially convertible into approximately 4.7 million shares of common stock which are included as outstanding shares in the diluted EPS calculation (see Note 19). The conversion of these senior notes into shares of Duke Energy common stock is contingent upon the occurrence of certain events during specified periods. These events include whether the price of Duke Energy common stock reaches specified thresholds, the credit rating of Duke Energy falls below certain thresholds, the convertible notes are called for redemption by Duke Energy, or specified transactions have occurred. In addition to the aforementioned events that could trigger early redemption, holders of the senior notes may require Duke Energy to purchase all or a portion of their senior notes for cash on May 15, 2007, May 15, 2012, and May 15, 2017, at a price equal to the principal amount of the senior notes plus accrued interest, if any. Duke Energy may redeem for cash all or a portion of the senior notes at any time on or after May 20, 2007, at a price equal to the sum of the issue price plus accrued interest, if any, on the redemption date. These convertible senior notes became convertible into shares of Duke Energy common stock during fiscal quarters beginning April 1, 2006 due to the market price of Duke Energy common stock achieving a specified threshold for each respective quarter. Holders of the convertible senior notes were allowed to exercise their right to convert on or prior to December 31, 2006. During 2006, approximately 27 million shares of common stock were issued related to this conversion, which resulted in the retirement of approximately $632 million of convertible senior notes. During 2005, as a result of the same market price trigger, approximately 1.2 million shares of common stock were issued related to this conversion, which resulted in the retirement of approximately $28 million of convertible senior notes.

Secured Debt. *Accounts Receivable Securitization.* Duke Energy securitizes certain accounts receivable through Duke Energy Receivables Finance Company, LLC (DERF), a bankruptcy remote, special purpose subsidiary. DERF is a wholly owned limited liability company with a separate legal existence from its parent, and its assets are not intended to be generally available to creditors of Duke Energy. As a result of the securitization, Duke Energy sells on a daily basis to DERF, certain accounts receivable arising from the sale of electricity and/or related services as part of Duke Energy's franchised electric business. In order to fund its purchases of accounts receivable, DERF has a $300 million secured credit facility, with a commercial paper conduit administered by Citicorp North America, Inc. which terminates in September 2008. The credit facility and related securitization documentation contain several covenants, including covenants with respect to the accounts receivable held by DERF as well as a covenant requiring that the ratio of Duke Energy consolidated indebtedness to Duke Energy consolidated capitalization not exceed 65%. As of December 31, 2006, the interest rate associated with the credit facility, which is based on commercial paper rates, was 5.8% and $300 million was outstanding under the credit facility. The securitization transaction was not structured to meet the criteria for sale treatment under SFAS No. 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities," and accordingly is reflected as a secured borrowing in the Consolidated Financial Statements. As of December 31, 2006 and 2005, the $300 million outstanding balance of the credit facility was secured by approximately $476 million and $489 million, respectively, of accounts receivable held by DERF. The obligations of DERF under the credit facility are non-recourse to Duke Energy.

Other Assets Pledged as Collateral. As of December 31, 2006, secured debt also consisted of various project financings, including Maritimes & Northeast Pipeline, LLC, Maritimes & Northeast Pipeline, LP (collectively, M&N Pipeline). A portion of the assets, ownership interest and business contracts in these various projects are pledged as collateral. Additionally, as of December 31, 2006, substantially all of U.S. Franchised Electric and gas's electric plant in service was subject to a mortgage lien securing the first and refunding mortgage bonds.

Floating Rate Debt. Unsecured debt, secured debt and other debt included approximately $3.2 billion of floating-rate debt as of December 31, 2006, and $1.7 billion as of December 31, 2005. As of December 31, 2006 and 2005, $500 million and $488 million of Brazilian debt that is indexed annually to Brazilian inflation was included in floating rate debt. Floating-rate debt is primarily based on commercial paper rates or a spread relative to an index such as a London Interbank Offered Rate for debt denominated in U.S. dollars, and Banker's Acceptances for debt denominated in Canadian dollars. As of December 31, 2006 and 2005, the average interest rate associated with floating-rate debt was approximately 4.8% and 6.4%, respectively.

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

At December 31, 2006, Other debt included approximately $326 million of notes payable related to Cinergy's Trust Preferred Securities (see Note 23), which will mature in February 2007. The entire outstanding balance of the debt is classified within Current Maturities of Long-term Debt on the Consolidated Balance Sheets at December 31, 2006.

Maturities, Call Options and Acceleration Clauses.

Annual Maturities as of December 31, 2006

	(in millions)
2007	$ 1,605
2008	2,109
2009	1,634
2010	1,435
2011	604
Thereafter	12,336
Total long-term debt[a]	$ 19,723

(a) Excludes short-term notes payable and commercial paper of $450 million.

Duke Energy has the ability under certain debt facilities to call and repay the obligation prior to its scheduled maturity. Therefore, the actual timing of future cash repayments could be materially different than the above as a result of Duke Energy's ability to repay these obligations prior to their scheduled maturity.

Duke Energy may be required to repay certain debt should the credit ratings at Duke Energy Carolinas fall to a certain level at Standard & Poor's (S&P) or Moody's Investor Service (Moody's). As of December 31, 2006, Duke Energy had $13 million of senior unsecured notes which mature serially through 2012 that may be required to be repaid if Duke Energy's senior unsecured debt ratings fall below BBB– at S&P or Baa3 at Moody's, and $23 million of senior unsecured notes which mature serially through 2016 that may be required to be repaid if Duke Energy's senior unsecured debt ratings fall below BBB at S&P or Baa2 at Moody's. As of February 1, 2007, Duke Energy Carolinas' senior unsecured credit rating was BBB at S&P and A3 at Moody's.

Available Credit Facilities and Restrictive Debt Covenants. During the year ended December 31, 2006, Duke Energy's consolidated credit capacity increased by approximately $842 million compared to December 31, 2005 primarily due to the merger with Cinergy. This increase was net of other reductions in credit capacity due to the terminations of an $800 million syndicated credit facility and $590 million of other bi-lateral credit facilities. The terminations of these credit facilities primarily reflect Duke Energy's reduced liquidity needs as a result of exiting the former DENA business.

The issuance of commercial paper, letters of credit and other borrowings reduces the amount available under the available credit facilities.

Duke Energy's debt and credit agreements contain various financial and other covenants. Failure to meet those covenants beyond applicable grace periods could result in accelerated due dates and/or termination of the agreements. As of December 31, 2006, Duke Energy was in compliance with those covenants. In addition, some credit agreements may allow for acceleration of payments or termination of the agreements due to nonpayment, or to the acceleration of other significant indebtedness of the borrower or some of its subsidiaries. None of the debt or credit agreements contain material adverse change clauses.

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

Credit Facilities Summary as of December 31, 2006 (in millions)

	Expiration Date	Credit Facilities Capacity	Amounts Outstanding Commercial Paper	Letters of Credit	Total
Duke Energy Corporation					
$400 364-day syndicated[a], [b]					
Total Duke Energy Corporation	December 2007	$ 400	$ —	$ 111	$111
Duke Energy Carolinas, LLC					
$600 multi-year syndicated[a], [b], [c]	June 2011		300	4	304
$75 three-year bi-lateral[a], [b]	September 2009				
$75 three-year bi-lateral[a], [b]	September 2009				
Total Duke Energy Carolinas, LLC		750	300	4	304
Spectra Energy Capital LLC					
$600 multi-year syndicated[a], [b]	June 2010		—	13	13
$350 364-day syndicated[b]	November 2007		350	—	350
Total Spectra Energy Capital LLC		950	350	13	363
Westcoast Energy Inc.					
$173 multi-year syndicated[d]	June 2011	173	—	—	—
Union Gas Limited					
$345 364-day syndicated[e]	June 2007	345	—	—	—
Cinergy Corp.					
$1,500 multi-year syndicated[a], [b], [f]	June 2011	1,500	100	11	111
Total[g]		$ 4,118	$750	$ 139	$889

(a) Credit facility contains an option allowing borrowing up to the full amount of the facility on the day of initial expiration for up to one year.

(b) Credit facility contains a covenant requiring the debt-to-total capitalization ratio to not exceed 65%.

(c) Credit facility increased from $500 million to $600 million in November 2006.

(d) Credit facility is denominated in Canadian dollars totaling 200 million Canadian dollars and contains a covenant that requires the debt-to-total capitalization ratio to not exceed 75%.

(e) Credit facility is denominated in Canadian dollars totaling 400 million Canadian dollars and contains a covenant that requires the debt-to-total capitalization ratio to not exceed 75% and an option at maturity allowing for the conversion of all outstanding loans to a term loan repayable up to one year after maturity date but not exceeding 18 months from the date of draw.

(f) Contains $500 million sub limits each for Duke Energy Ohio and Duke Energy Indiana and a $100 million sub limit for Duke Energy Kentucky. Credit facility decreased from $2.0 billion to $1.5 billion in November 2006.

(g) This summary excludes certain demand facilities and committed facilities that are immaterial in size or which generally support very specific requirements.

Duke Energy has approximately $1,095 million of credit facilities which expire in 2007, of which approximately $695 million relates to credit facilities of Spectra Energy Capital. Of the $400 million of expiring credit facilities remaining with Duke Energy subsequent to the spin-off of the natural gas businesses (see Note 1), it is Duke Energy's intent to resyndicate these expiring facilities and possibly increase the size of the facilities.

Other Loans. During 2006 and 2005, Duke Energy had loans outstanding against the cash surrender value of the life insurance policies that it owns on the lives of its executives. The amounts outstanding were $594 million as of December 31, 2006 and $552 million as of December 31, 2005. The amounts outstanding were carried as a reduction of the related cash surrender value that is included in Other Assets on the Consolidated Balance Sheets.

16. Preferred and Preference Stock at Duke Energy

As of December 31, 2006, as a result of the corporate restructuring in connection with the Cinergy merger, there were 44 million authorized shares of preferred stock, par value $0.001 per share, with no such preferred shares outstanding.

As of December 31, 2005, there were no shares of preferred and preference stock outstanding at Duke Energy.

Preferred Stock without Sinking Fund Requirements. In December 2005, Duke Energy redeemed all Preferred and Preference stock without Sinking Fund Requirements for approximately $137 million and recognized an immaterial loss on the redemption.

Preferred and Preference Stock of Duke Energy's Subsidiaries. In connection with the Westcoast acquisition in 2002, Duke Energy assumed approximately $411 million of authorized and issued redeemable preferred and preference shares at Westcoast and Union Gas. These preferred and preference shares at Westcoast and Union Gas totaled $225 million at both December 31, 2006 and 2005. Since these preferred and preference shares are redeemable at the option of holder, as well as Westcoast and Union Gas, these preferred and preference shares do not meet the definition of a mandatorily redeemable instrument under SFAS No. 150, "Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity." As such, these preferred and preference shares are considered contingently redeemable shares and are included in Minority Interests on the Consolidated Balance Sheets.

Additionally, in connection with the Cinergy merger in April 2006, Duke Energy assumed approximately $11 million of authorized and issued preferred stock at Duke Energy Indiana. All outstanding shares of Duke Energy Indiana preferred stock were redeemed in May 2006 at par, plus accrued and unpaid dividends.

17. Commitments and Contingencies

General Insurance

Duke Energy carries, either directly or through its captive insurance company, Bison, and its affiliates, insurance and reinsurance coverages consistent with companies engaged in similar commercial operations with similar type properties. Duke Energy's insurance coverage includes (1) commercial general public liability insurance for liabilities arising to third parties for bodily injury and property damage resulting from Duke Energy's operations; (2) workers' compensation liability coverage to required statutory limits; (3) automobile liability insurance for all owned, non-owned and hired vehicles covering liabilities to third parties for bodily injury and property damage; (4) insurance policies in support of the indemnification provisions of Duke Energy's by-laws and (5) property insurance covering the replacement value of all real and personal property damage, excluding electric transmission and distribution lines, including damages arising from boiler and machinery breakdowns, earthquake, flood damage and extra expense. All coverages are subject to certain deductibles, terms and conditions common for companies with similar types of operations.

In 2006, Bison was a member of Oil Insurance Limited (OIL) and sEnergy Insurance Limited (sEnergy), which provided property and business interruption reinsurance coverage respectively for Duke Energy's non-nuclear facilities. Duke Energy accounts for its memberships under the cost method, as it does not have the ability to exert significant influence over these investments. Bison terminated its membership in OIL effective December 31, 2006 and will pay a withdrawal premium during 2007 as a result of this decision. sEnergy ceased insuring events subsequent to May 15, 2006 and is currently winding down its operations and settling its outstanding claims. Bison will continue to pay additional premiums to sEnergy as it settles its outstanding claims during its wind-down. Duke Energy does not expect the termination of Bison's membership in OIL or the continued wind-down of sEnergy will have a material impact on its consolidated results of operations, cash flows, or financial position in 2007.

Duke Energy also maintains excess liability insurance coverage above the established primary limits for commercial general liability and automobile liability insurance. Limits, terms, conditions and deductibles are comparable to those carried by other energy companies of similar size.

The cost of Duke Energy's general insurance coverages continued to fluctuate over the past year reflecting the changing conditions of the insurance markets.

Nuclear Insurance

Duke Energy owns and operates the McGuire and Oconee Nuclear Stations and operates and has a partial ownership interest in the Catawba Nuclear Station. The McGuire and Catawba Nuclear Stations have two nuclear reactors each and Oconee has three. Nuclear insurance includes: liability coverage; property, decontamination and premature decommissioning coverage; and business interruption and/or extra expense coverage. The other joint owners of the Catawba Nuclear Station reimburse Duke Energy for certain expenses associated with nuclear insurance premiums. The Price-Anderson Act requires Duke Energy to insure against public liability claims resulting from nuclear incidents to the full limit of liability, approximately $10.8 billion.

Primary Liability Insurance. Duke Energy has purchased the maximum available private primary liability insurance as required by law, which is $300 million.

Excess Liability Program. This program currently provides approximately $10.5 billion of coverage through the Price-Anderson Act's mandatory industry-wide excess secondary financial protection program of risk pooling. The $10.5 billion is the sum of the current potential cumulative retrospective premium assessments of $101 million per licensed commercial nuclear reactor. This would be increased by $101 million for each additional commercial nuclear reactor licensed, or reduced by $101 million for nuclear reactors no longer operational and may be exempted from the risk pooling insurance program. Under this program, licensees could be assessed retrospective premiums to compensate for damages in the event of a nuclear incident at any licensed facility in the U.S. If such an incident should occur and public liability damages exceed primary insurances, licensees may be assessed up to $101 million for each of their licensed reactors, payable at a rate not to exceed $15 million a year per licensed reactor for each incident. The $101 million is subject to indexing for inflation and may be subject to state premium taxes.

Duke Energy is a member of Nuclear Electric Insurance Limited (NEIL), which provides accidental outage insurance coverage for Duke Energy's nuclear facilities under three policy programs:

Primary Property Insurance. This policy provides $500 million of primary property damage coverage for each of Duke Energy's nuclear facilities.

Excess Property Insurance. This policy provides excess property, decontamination and decommissioning liability insurance: $2.25 billion for the Catawba Nuclear Station and $2.0 billion each for the Oconee and McGuire Nuclear Stations.

Accidental Outage Insurance. This policy provides business interruption and/or extra expense coverage resulting from an accidental outage of a nuclear unit. Each McGuire and Catawba unit is insured for up to $3.5 million per week, and the Oconee units are insured for up to $2.8 million per week. Coverage amounts decline if more than one unit is involved in an accidental outage. Initial coverage begins after a 12-week deductible period for Catawba and a 26-week deductible period for McGuire and Oconee and continues at 100% for 52 weeks and 80% for the next 110 weeks.

If NEIL's losses exceed its reserves for any of the above three programs, Duke Energy is liable for assessments of up to 10 times its annual premiums. The current potential maximum assessments are: Primary Property Insurance—$38 million, Excess Property Insurance—$46 million and Business Interruption Insurance—$22 million.

The other joint owners of the Catawba Nuclear Station are obligated to assume their pro rata share of liability for retrospective premiums and other premium assessments resulting from the Price-Anderson Act's excess secondary financial protection program of risk pooling, or the NEIL policies.

Environmental

Duke Energy is subject to international, federal, state and local regulations regarding air and water quality, hazardous and solid waste disposal and other environmental matters. These regulations can be changed from time to time, imposing new obligations on Duke Energy.

Remediation activities. Like others in the energy industry, Duke Energy and its affiliates are responsible for environmental remediation at various contaminated sites. These include some properties that are part of ongoing Duke Energy operations, sites formerly owned or used by Duke Energy entities, and sites owned by third parties. Remediation typically involves management of contaminated soils and may involve groundwater remediation. Managed in conjunction with relevant federal, state and local agencies, activities vary with site conditions and locations, remedial requirements, complexity and sharing of responsibility. If remediation activities involve statutory joint and several liability provisions, strict liability, or cost recovery or contribution actions, Duke Energy or its affiliates could potentially be held responsible for contamination caused by other parties. In some instances, Duke Energy may share liability associated with contamination with other potentially responsible parties, and may also benefit from insurance policies or contractual indemnities that cover some or all cleanup costs. All of these sites generally are managed in the normal course of business or affiliate

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

operations. Management believes that completion or resolution of these matters will have no material adverse effect on Duke Energy's consolidated results of operations, cash flows or financial position.

Clean Water Act. The U.S. Environmental Protection Agency's (EPA's) final Clean Water Act Section 316(b) rule became effective July 9, 2004. The rule established aquatic protection requirements for existing facilities that withdraw 50 million gallons or more of water per day from rivers, streams, lakes, reservoirs, estuaries, oceans, or other U.S. waters for cooling purposes. Fourteen of the 23 coal and nuclear-fueled generating facilities in which Duke Energy is either a whole or partial owner are affected sources under that rule. On January 25, 2007, the U.S. Court of Appeals for the Second Circuit issued its opinion in *Riverkeeper, Inc. v. EPA*, Nos. 04-6692-ag(L) et. al. (2d Cir. 2007) remanding most aspects of EPA's rule back to the agency. The court effectively disallowed those portions of the rule most favorable to industry, and the decision creates a great deal of uncertainty regarding future requirements and their timing. While Duke Energy is still unable to estimate costs to comply with the EPA's rule, it is expected that costs will increase as a result of the court's decision. The magnitude of any such increase cannot be estimated at this time.

Clean Air Mercury Rule (CAMR) and Clean Air Interstate Rule (CAIR). The EPA finalized its CAMR and CAIR in May 2005. The CAMR limits total annual mercury emissions from coal-fired power plants across the United States through a two-phased cap-and-trade program. Phase 1 begins in 2010 and Phase 2 begins in 2018. The CAIR limits total annual and summertime nitrogen oxides (NOx) emissions and annual sulfur dioxide (SO_2) emissions from electric generating facilities across the Eastern United States through a two-phased cap-and-trade program. Phase 1 begins in 2009 for NOx and in 2010 for SO_2. Phase 2 begins in 2015 for both NOx and SO_2.

The emission controls Duke Energy is installing to comply with North Carolina clean air legislation will contribute significantly to achieving compliance with CAMR and CAIR requirements (see Note 4). In addition, Duke Energy currently estimates that it will spend approximately $710 million between 2007 and 2011 to comply with Phase 1 of CAMR and CAIR at its Midwest electric operations. Duke Energy currently estimates that any additional costs it might incur to comply with Phase 1 of CAMR or CAIR will have no material adverse effect on its consolidated results of operations, cash flows or financial position. Duke Energy currently estimates its CAIR Phase 2 compliance costs at approximately $150 million for Duke Energy Carolinas' electric operations over the period 2010-2016. Duke Energy estimates its CAIR/CAMR Phase 2 compliance costs at approximately $450 million for its Midwest electric operations over the period 2007-2016. Duke Energy is currently unable to estimate the cost of complying with Phase 2 of CAMR beyond 2016. The IURC issued an order in 2006 granting Duke Energy Indiana approximately $1.08 billion in rate recovery to cover its estimated Phase 1 of CAIR/CAMR compliance costs in Indiana (see Note 4). Duke Energy Ohio receives partial recovery of depreciation and financing costs related to environmental compliance projects for 2005-2008 through its rate stabilization plan (see Note 4).

Extended Environmental Activities, Accruals. Included in Other Current Liabilities and Other Deferred Credits and Other Liabilities on the Consolidated Balance Sheets were total accruals related to extended environmental-related activities of approximately $73 million and $55 million as of December 31, 2006 and 2005, respectively. These accruals represent Duke Energy's provisions for costs associated with remediation activities at some of its current and former sites, as well as other relevant environmental contingent liabilities. Management believes that completion or resolution of these matters will have no material adverse effect on Duke Energy's consolidated results of operations, cash flows or financial position.

Litigation

New Source Review (NSR). In 1999-2000, the U.S. Justice Department, acting on behalf of the EPA, filed a number of complaints and notices of violation against multiple utilities across the country for alleged violations of the NSR provisions of the Clean Air Act (CAA). Generally, the government alleged that projects performed at various coal-fired units were major modifications, as defined in the CAA, and that the utilities violated the CAA when they undertook those projects without obtaining permits and installing emission controls for SO_2, NOx and particulate matter. The complaints seek (1) injunctive relief to require installation of pollution control technology on various allegedly violating generating units, and (2) unspecified civil penalties in amounts of up to $27,500 per day for each violation. A number of Duke Energy's owned and operated plants have been subject to these allegations and lawsuits. Duke Energy asserts that there were no CAA violations because the applicable regulations do not require permitting in cases where the projects undertaken are "routine" or otherwise do not result in a net increase in emissions.

In 2000, the government brought a lawsuit against Duke Energy in the U.S. District Court in Greensboro, North Carolina. The EPA claims that 29 projects performed at 25 of Duke Energy's coal-fired units in the Carolinas violate these NSR provisions. In August 2003, the trial Court issued a summary judgment opinion adopting Duke Energy's legal positions, and on April 15, 2004, the Court entered Final

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

Judgment in favor of Duke Energy. The government appealed the case to the U.S. Fourth Circuit Court of Appeals. On June 15, 2005, the Fourth Circuit ruled in favor of Duke Energy and effectively adopted Duke Energy's view that permitting of projects is not required unless the work performed causes a net increase in the hourly rate of emissions. The Fourth Circuit did not reach the question of "routine". The EPA sought rehearing in the Fourth Circuit, which was denied. Environmental intervenors in the case sought a writ of certiorari to the U.S. Supreme Court, which was granted. On November 1, 2006, oral arguments were made before the U.S. Supreme Court.

In November 1999, the United States brought a lawsuit in the United States Federal District Court for the Southern District of Indiana against Cinergy, Duke Energy Ohio, and Duke Energy Indiana alleging various violations of the CAA for various projects at six of Duke Energy owned and co-owned generating stations in the Midwest. Additionally, the suit claims that Duke Energy violated an Administrative Consent Order entered into in 1998 between the EPA and Cinergy relating to alleged violations of Ohio's State Implementation Plan (SIP) provisions governing particulate matter at Unit 1 at Duke Energy Ohio's W.C. Beckjord Station. In addition, three northeast states and two environmental groups have intervened in the case. In August 2005, the district court issued a ruling regarding the emissions test that it will apply to Cinergy, Duke Energy Ohio, and Duke Energy Indiana at the trial of the case. Contrary to Cinergy's, Duke Energy Ohio's, and Duke Energy Indiana's argument (and the decision of the district court in the Duke Carolinas NSR case described above), the district court ruled that in determining whether a project was projected to increase annual emissions, it would not hold hours of operation constant. However, the district court subsequently certified the matter for interlocutory appeal to the Seventh Circuit Court of Appeals. In August 2006, the Seventh Circuit upheld the district court's opinion. Cinergy has petitioned the U.S. Supreme Court for a writ of certiorari, which is pending. This issue is before the U.S. Supreme Court in the Duke Energy Carolinas NSR case, and we do not expect further dispositive legal proceedings in this case until after the Supreme Court ruling.

In March 2000, the United States also filed in the United States District Court for the Southern District of Ohio an amended complaint in a separate lawsuit alleging violations of the CAA regarding various generating stations, including a generating station operated by Columbus Southern Power Company (CSP) and jointly-owned by CSP, The Dayton Power and Light Company (DP&L), and Duke Energy Ohio. This suit is being defended by CSP (the CSP case). In April 2001, the United States District Court for the Southern District of Ohio in that case ruled that the Government and the intervening plaintiff environmental groups cannot seek monetary damages for alleged violations that occurred prior to November 3, 1994; however, they are entitled to seek injunctive relief for such alleged violations. Neither party appealed that decision. This matter was heard in trial in July 2005. A decision is pending, but any finding of liability will also be dependent upon the Supreme Court's decision in the Duke Energy Carolinas case.

In addition, Cinergy and Duke Energy Ohio have been informed by DP&L that in June 2000, the EPA issued a Notice of Violation (NOV) to DP&L for alleged violations of CAA requirements at a station operated by DP&L and jointly-owned by DP&L, CSP, and Duke Energy Ohio. The NOV indicated the EPA may (1) issue an order requiring compliance with the requirements of the Ohio SIP, or (2) bring a civil action seeking injunctive relief and civil penalties of up to $27,500 per day for each violation. In September 2004, Marilyn Wall and the Sierra Club brought a lawsuit against Duke Energy Ohio, DP&L and CSP for alleged violations of the CAA at this same generating station. This case is currently in discovery in front of the same judge who has the CSP case.

It is not possible to predict with certainty whether Duke Energy will incur any liability or to estimate the damages, if any, that Duke Energy might incur in connection with these matters.

Carbon Dioxide Litigation. In July 2004, the states of Connecticut, New York, California, Iowa, New Jersey, Rhode Island, Vermont, Wisconsin, and the City of New York brought a lawsuit in the United States District Court for the Southern District of New York against Cinergy, American Electric Power Company, Inc., American Electric Power Service Corporation, The Southern Company, Tennessee Valley Authority, and Xcel Energy Inc. A similar lawsuit was filed in the United States District Court for the Southern District of New York against the same companies by Open Space Institute, Inc., Open Space Conservancy, Inc., and The Audubon Society of New Hampshire. These lawsuits allege that the defendants' emissions of carbon dioxide (CO_2) from the combustion of fossil fuels at electric generating facilities contribute to global warming and amount to a public nuisance. The complaints also allege that the defendants could generate the same amount of electricity while emitting significantly less CO_2. The plaintiffs are seeking an injunction requiring each defendant to cap its CO_2 emissions and then reduce them by a specified percentage each year for at least a decade. In September 2005, the district court granted the defendants' motion to dismiss the lawsuit. The plaintiffs have appealed this ruling to the Second Circuit Court of Appeals. Oral argument was held before the Second Circuit Court of Appeals on June 7, 2006.

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

It is not possible to predict with certainty whether Duke Energy will incur any liability or to estimate the damages, if any, that Duke Energy might incur in connection with this matter.

Hurricane Katrina Lawsuit. In April 2006, Duke Energy and Cinergy were named in the third amended complaint of a purported class action lawsuit filed in the United States District Court for the Southern District of Mississippi. Plaintiffs claim that Duke Energy and Cinergy, along with numerous other utilities, oil companies, coal companies and chemical companies, are liable for damages relating to losses suffered by victims of Hurricane Katrina. Plaintiffs claim that defendants' greenhouse gas emissions contributed to the frequency and intensity of storms such as Hurricane Katrina. In October 2006, Duke Energy and Cinergy were served with this lawsuit. It is not possible to predict with certainty whether Duke Energy or Cinergy will incur any liability or to estimate the damages, if any, that Duke Energy or Cinergy might incur in connection with this matter.

San Diego Price Indexing Cases. Duke Energy and several of its affiliates, as well as other energy companies, are parties to 25 lawsuits which have been coordinated as the "Price Indexing Cases" in San Diego, California. Twelve of the lawsuits seek class-action certification. The plaintiffs allege that the defendants conspired to manipulate price of natural gas in violation of state and/or federal antitrust laws, unfair business practices and other laws. Plaintiffs in some of the cases further allege that such activities, including engaging in "round trip" trades, providing false information to natural gas trade publications and unlawfully exchanging information, resulted in artificially high energy prices. In December 2006, Duke Energy executed an agreement to settle the 12 class action cases. Such agreement is subject to execution of mutually acceptable agreements and approval by the class members and the court. Duke Energy does not expect that the proposed settlement will have a material adverse effect on its consolidated results of operations, cash flows or financial position.

Other Price Reporting Cases. A total of 11 lawsuits have been filed against Duke Energy affiliates and other energy companies, including a lawsuit filed in December 2006 in Wisconsin state court. In February 2007, Duke Energy was served in the Wisconsin case. Six of these cases were dismissed on filed rate and/or federal preemption grounds, and the plaintiffs in each of these dismissed cases have appealed their respective rulings to the U.S. Ninth Circuit Court of Appeals. Oral argument on these appeals was heard February 13, 2007. Each of these cases contains similar claims, that the respective plaintiffs, and the classes they claim to represent, were harmed by the defendants' alleged manipulation of the natural gas markets by various means, including providing false information to natural gas trade publications and entering into unlawful arrangements and agreements in violation of the antitrust laws of the respective states. Plaintiffs seek damages in unspecified amounts. Duke Energy is unable to express an opinion regarding the probable outcome or estimate damages, if any, related to these matters at this time.

Western Electricity Litigation. Plaintiffs, on behalf of themselves and others, in three lawsuits allege that Duke Energy Affiliates, among other energy companies, artificially inflated the price of electricity in certain western states. Two of the cases were dismissed and plaintiffs have appealed to the U.S. Court of Appeal for the Ninth Circuit. In December 2006, a fourth case, the single remaining electricity case pending in California state court was dismissed. Plaintiffs in these cases seek damages in unspecified amounts, but which could total billions of dollars. It is not possible to predict with certainty whether Duke Energy will incur any liability or to estimate the damages, if any, that Duke Energy might incur in connection with these lawsuits, but Duke Energy does not presently believe the outcome of these matters will have a material adverse effect on its results of operations, cash flows or financial position.

Trading Related Investigations. Beginning in February 2004, Duke Energy has received requests for information from the U.S. Attorney's office in Houston focused on the natural gas price reporting activities of certain individuals involved in DETM trading operations. Duke Energy has cooperated with the government in this investigation and is unable to express an opinion regarding the probable outcome or estimate damages, if any, related to this matter at this time.

Southern California Edison. In 2002, Southern California Edison Company initiated arbitration proceedings regarding disputes with DETM relating to amounts owed in connection with the termination of bi-lateral power contracts between the parties in early 2001. This matter proceeded to hearing in November 2005. In January 2006, the parties reached an agreement in principle to resolve the matters at issue in the arbitration. The parties entered into a Settlement Agreement and Mutual Release dated as of March 10, 2006, and on March 24, 2006, DETM paid the settlement amount, including interest, into escrow. The agreement received final regulatory approval in October 2006. The resolution of this matter did not have a material adverse effect on Duke Energy's consolidated results of operations, cash flows or financial position.

Trading Related Litigation. Commencing August 2003, plaintiffs filed three class-action lawsuits in the U.S. District Court for the Southern District of New York on behalf of entities who bought and sold natural gas futures and options contracts on the New York Mer —

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

cantile Exchange during the years 2000 through 2002. DETM and CMT, along with numerous other entities, were named as defendants. The plaintiffs claim that the defendants violated the Commodity Exchange Act by reporting false and misleading trading information to trade publications, resulting in monetary losses to the plaintiffs. Plaintiffs seek class action certification, unspecified damages and other relief. On September 24, 2004, the court denied a motion to dismiss the plaintiffs' claims filed on behalf of DETM and other defendants, and on September 30, 2005, the court certified the class. Duke Energy has reached an agreement with the plaintiffs in these consolidated cases to resolve all issues and on February 8, 2006, the court granted preliminary approval of this settlement. The Final Judgment and Order of Dismissal were entered in May 2006. The resolution of this matter did not have a material adverse effect on Duke Energy's consolidated results of operations, cash flows or financial position.

Sonatrach/Sonatrading Arbitration. Duke Energy LNG Sales Inc. (Duke LNG) claims in an arbitration commenced in January 2001 in London that Sonatrach, the Algerian state-owned energy company, together with its subsidiary, Sonatrading Amsterdam B.V. (Sonatrading), breached their shipping obligations under a liquefied natural gas (LNG) purchase agreement and related transportation agreements (the LNG Agreements) relating to Duke LNG's purchase of LNG from Algeria and its transportation by LNG tanker to Lake Charles, Louisiana. Duke LNG seeks damages of approximately $27 million. Sonatrading and Sonatrach, on the other hand, claim that Duke LNG repudiated the LNG Agreements by allegedly failing to diligently perform LNG marketing obligations. Sonatrading and Sonatrach seek damages in the amount of approximately $250 million. In 2003, an arbitration tribunal issued a Partial Award on liability issues, finding that Sonatrach and Sonatrading breached their obligations to provide shipping. The tribunal also found that Duke LNG breached the LNG Purchase Agreement by failing to perform marketing obligations. The final hearing on damages was concluded in March 2006, and the tribunal issued its award on damages on November 30, 2006. Duke LNG was awarded approximately $20 million, plus interest, for Sonatrach's breach of its shipping obligations. Sonatrach and Sonatrading were awarded an unspecified amount that management believes will, when calculated, be substantially less than the amount awarded to Duke LNG, and result ultimately in a net positive, but immaterial, award to Duke LNG. This matter was assigned to Spectra Energy in connection with the spin-off in January 2007.

Citrus Trading Corporation (Citrus) Litigation. In conjunction with the Sonatrach LNG Agreements, Duke LNG entered into a natural gas purchase contract (the Citrus Agreement) with Citrus. Citrus filed a lawsuit in March 2003 in the U.S. District Court for the Southern District of Texas against Duke LNG and PanEnergy Corp alleging that Duke LNG breached the Citrus Agreement by failing to provide sufficient volumes of gas to Citrus. Duke LNG contends that Sonatrach caused Duke LNG to experience a loss of LNG supply that affected Duke LNG's obligations and termination rights under the Citrus Agreement. Citrus seeks monetary damages and a judicial determination that Duke LNG did not experience such a loss. After Citrus filed its lawsuit, Duke LNG terminated the Citrus Agreement and filed a counterclaim asserting that Citrus had breached the agreement by, among other things, failing to provide sufficient security under a letter of credit for the gas transactions. Citrus denies that Duke LNG had the right to terminate the agreement and contends that Duke LNG's termination of the agreement was itself a breach, entitling Citrus to terminate the agreement and recover damages in the amount of approximately $190 million (excluding interest). This matter and the financial obligation of any settlement or judgment were assigned to Spectra Energy in connection with the spin-off in January 2007. In January 2007 Spectra Energy and Citrus settled this litigation for a payment by Spectra Energy to Citrus of $100 million. As a result, in 2006, Duke Energy recognized a reserve of $100 million related to the settlement offer.

ExxonMobil Disputes. In April 2004, Mobil Natural Gas, Inc. (MNGI) and 3946231 Canada, Inc. (3946231, and collectively with MNGI, ExxonMobil) filed a Demand for Arbitration against Duke Energy, DETMI Management Inc. (DETMI), DTMSI Management Ltd. (DTMSI) and other affiliates of Duke Energy. MNGI and DETMI are the sole members of DETM. DTMSI and 3946231 are the sole beneficial owners of Duke Energy Marketing Limited Partnership (DEMLP, and with DETM, the Ventures). Among other allegations, ExxonMobil alleges that DETMI and DTMSI engaged in wrongful actions relating to affiliate trading, payment of service fees, expense allocations and distribution of earnings in breach of agreements and fiduciary duties relating to the Ventures. ExxonMobil seeks to recover actual damages, plus attorneys' fees and exemplary damages; aggregate damages were specified at the arbitration hearing and totaled approximately $125 million (excluding interest). Duke Energy denies these allegations, and has filed counterclaims asserting that ExxonMobil breached its Venture obligations and other contractual obligations. By order dated May 2, 2005, the arbitrators granted Duke Energy's Motion for Partial Summary Judgment, effectively eliminating a significant portion of ExxonMobil's claims. ExxonMobil filed a motion for reconsideration of the ruling as well as for an extension of the date for the arbitration hearing. ExxonMobil also filed a motion to dismiss certain of Duke Energy's counterclaims. Following a hearing in December 2005 on the motion for reconsideration, the arbitrators issued their ruling on January 26, 2006, generally reaffirming the original order, with a limited exception with respect to affiliate trades that is not expected to have a significant impact on the case. The panel also dismissed one of Duke Energy's counterclaims. The parties agreed that the dam ages due to Duke Energy on its counterclaim will be determined in the upcoming hearing scheduled in the Canadian arbitration proceedings. The arbitration hearing in the U.S. arbitration was held in October 2006 in Houston, Texas, with a subsequent hearing in January 2007. In August 2004, DEMLP initiated arbitration proceedings in Canada against certain ExxonMobil entities asserting that those entities wrongfully terminated two gas supply agreements with the DEMLP and wrongfully failed to assume certain related gas supply agreements with other parties. A hearing in the Canadian arbitration was held in March 2006. The arbitrators issued their award in June, 2006 finding that (1) the two gas supply agreements were improperly terminated by ExxonMobil; but (2) ExxonMobil was not required to take assignment of the related third party gas supply agreements. Hearings to determine the damages to be paid as the result of the first ruling, as well as the damages to be paid to Duke Energy as the result of the termination of the U.S. gas supply agreement were held on November 9 and 10, 2006, and January 22, 2007, before the same panel of arbitrators. In February 2007, Duke Energy and ExxonMobil reached agreement in principle on a global settlement of both arbitrations. Such agreement is subject to execution of final settlement documents. Duke Energy does not expect that the proposed settlement will have a material effect on its consolidated results of operations, cash flows or financial position. The gas supply agreements with other parties, under which DEMLP continues to remain obligated, are currently estimated to result in losses of between $50 million and $100 million through 2011. As Duke Energy has an ownership interest of approximately 60% in DEMLP, only 60% of any losses would impact pretax earnings for Duke Energy. However, these losses are subject to change in the future in the event of changes in market conditions and underlying assumptions.

Duke Energy Retirement Cash Balance Plan. A class action lawsuit has been filed in federal court in South Carolina against Duke Energy and the Duke Energy Retirement Cash Balance Plan, alleging violations of Employee Retirement Income Security Act (ERISA) and the Age Discrimination in Employment Act. These allegations arise out of the conversion of the Duke Energy Company Employees' Retirement Plan into the Duke Energy Retirement Cash Balance Plan. The case also raises some Plan administration issues, alleging errors in the application of Plan provisions (*e.g.*, the calculation of interest rate credits in 1997 and 1998 and the calculation of lump-sum distributions). The plaintiffs seek to represent present and former participants in the Duke Energy Retirement Cash Balance Plan. This group is estimated to include approximately 36,000 persons. The plaintiffs also seek to divide the putative class into sub-classes based on age. Six causes of action are alleged, ranging from age discrimination, to various alleged ERISA violations, to allegations of breach of fiduciary duty. The plaintiffs seek a broad array of remedies, including a retroactive reformation of the Duke Energy Retirement Cash Balance Plan and a recalculation of participants'/ beneficiaries' benefits under the revised and reformed plan. Duke Energy filed its answer in March 2006. A second class action lawsuit was filed in federal court in South Carolina, alleging similar claims and seeking to represent the same class of defendants. The second case has been voluntarily dismissed, without prejudice, effectively consolidating it with the first case. A portion of this liability was assigned to Spectra Energy in connection with the spin-off in January 2007. The matter is currently in discovery with a tentative trial date of March 2008. It is not possible to predict with certainty whether Duke Energy will incur any liability or to estimate the damages, if any, that Duke Energy might incur in connection with this matter.

Asbestos-related Injuries and Damages Claims. Duke Energy has experienced numerous claims relating to damages for personal injuries alleged to have arisen from the exposure to or use of asbestos in connection with construction and maintenance activities conducted by Duke Energy Carolinas on its electric generation plants during the 1960s and 1970s. Duke Energy has third-party insurance to cover losses related to these asbestos-related injuries and damages above a certain aggregate deductible. The insurance policy, including the policy deductible and reserves, provided for coverage to Duke Energy up to an aggregate of $1.6 billion when purchased in 2000. Probable insurance recoveries related to this policy are classified in the Consolidated Balance Sheets as Other within Investments and Other Assets. Amounts recognized as reserves in the Consolidated Balance Sheets, which are not anticipated to exceed the coverage, are classified in Other Deferred Credits and Other Liabilities and Other Current Liabilities and are based upon Duke Energy's best estimate of the probable liability for future asbestos claims. These reserves are based upon current estimates and are subject to uncertainty. Factors such as the frequency and magnitude of future claims could change the current estimates of the related reserves and claims for recoveries reflected in the accompanying Consolidated Financial Statements. However, management of Duke Energy does not currently anticipate that any changes to these estimates will have any material adverse effect on Duke Energy's consolidated results of operations, cash flows or financial position.

Duke Energy Indiana and Duke Energy Ohio have been named as defendants or co-defendants in lawsuits related to asbestos at their electric generating stations. Currently, there are approximately 130 pending lawsuits (the majority of which are Duke Energy Indiana cases). In these lawsuits, plaintiffs claim to have been exposed to asbestos-containing products in the course of their work as outside contractors. The plaintiffs further claim that as the property owner of the generating stations, Duke Energy Indiana and Duke Energy Ohio should be held liable for their injuries and illnesses based on an alleged duty to warn and protect them from any asbestos exposure. The impact on Duke Energy's financial position, cash flows, or results of operations of these cases to date has not been material.

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

Of these lawsuits, one case filed against Duke Energy Indiana has been tried to verdict. The jury returned a verdict against Duke Energy Indiana on a negligence claim and a verdict for Duke Energy Indiana on punitive damages. Duke Energy Indiana appealed this decision up to the Indiana Supreme Court. In October 2005, the Indiana Supreme Court upheld the jury's verdict. Duke Energy Indiana paid the judgment of approximately $630,000 in the fourth quarter of 2005. In addition, Duke Energy Indiana has settled over 150 other claims for amounts, which neither individually nor in the aggregate, are material to Duke Energy Indiana's financial position or results of operations. Based on estimates under varying assumptions, concerning uncertainties, such as, among others: (i) the number of contractors potentially exposed to asbestos during construction or maintenance of Duke Energy Indiana generating plants; (ii) the possible incidence of various illnesses among exposed workers, and (iii) the potential settlement costs without federal or other legislation that addresses asbestos tort actions, Duke Energy estimates that the range of reasonably possible exposure in existing and future suits over the next 50 years could range from an immaterial amount to approximately $60 million, exclusive of costs to defend these cases. This estimated range of exposure may change as additional settlements occur and claims are made in Indiana and more case law is established.

Duke Energy Ohio has been named in fewer than 10 cases and as a result has virtually no settlement history for asbestos cases. Thus, Duke Energy is not able to reasonably estimate the range of potential loss from current or future lawsuits. However, potential judgments or settlements of existing or future claims could be material to Duke Energy.

Other Litigation and Legal Proceedings. Duke Energy and its subsidiaries are involved in other legal, tax and regulatory proceedings arising in the ordinary course of business, some of which involve substantial amounts. Management believes that the final disposition of these proceedings will not have a material adverse effect on Duke Energy's consolidated results of operations, cash flows or financial position.

Duke Energy has exposure to certain legal matters that are described herein. As of December 31, 2006, Duke Energy has recorded reserves of approximately $1.3 billion for these proceedings and exposures. Duke Energy has insurance coverage for certain of these losses incurred. As of December 31, 2006, Duke Energy has recognized approximately $1.0 billion of probable insurance recoveries related to these losses. These reserves represent management's best estimate of probable loss as defined by SFAS No. 5, "Accounting for Contingencies."

Duke Energy expenses legal costs related to the defense of loss contingencies as incurred.

Other Commitments and Contingencies

Commercial Power produces synthetic fuel from facilities that qualify for tax credits (through 2007) in accordance with Section 29/45K of the Internal Revenue Code if certain requirements are satisfied. These credits reduce Duke Energy's income tax liability and therefore Duke Energy's effective tax rate. Commercial Power's sale of synthetic fuel has generated $339 million in tax credits through December 31, 2005. During the first quarter of 2006, an agreement was in place with the plant operator which would indemnify Duke Energy in the event that tax credits are insufficient to support operating expenses. This agreement did not continue for the remainder of 2006. After reducing for the possibility of phase-outs in 2006, the amount of additional credits generated through December 31, 2006 was approximately $20 million. Duke Energy's net investment in the plants at December 31, 2006 was approximately $20 million.

Section 29/45K provides for a phase-out of the credit if the average price of crude oil during a calendar year exceeds a specified threshold. The phase-out is based on a prescribed calculation and definition of crude oil prices. If Commercial Power were to operate its synthetic fuel facilities based on December 31, 2006 prices throughout the entire forthcoming year, yet crude oil prices were to rise such that the tax credit is completely phased-out, net income in 2007 would be negatively impacted. Duke Energy is unlikely to experience a material loss because the exposure to synthetic fuel tax credit phase-out is monitored and Duke Energy may choose to reduce or cease synthetic fuel production depending on the expectation of any potential tax credit phase-out. Duke Energy may also reduce its exposure to crude prices through the execution of derivative transactions. The objective of these activities is to reduce potential losses incurred if the reference price in a year exceeds a level triggering a phase-out of synthetic fuel tax credits.

In August 2006, Duke Energy successfully completed the sale of one of its synthetic fuel facilities resulting in an immaterial gain. This sale was driven by Internal Revenue Service (IRS) requirements that stipulate that in order to qualify for tax credits in accordance with Section 29/45K, the sales of the synthetic fuel must be made to an unrelated third party.

The IRS has completed the audit of Cinergy for the 2002, 2003, and 2004 tax years including the synthetic fuel facility owned during that period. That facility represents $219 million of tax credits generated during that audit period. The IRS has not proposed any adjustment that would disallow the credits claimed during that period. Subsequent periods are still subject to audit. Duke Energy believes that it operates in conformity with all the necessary requirements to be allowed such credits under Section 29/45K.

Duke Energy is party to an agreement with a third party service provider related to future purchases to be made through late 2007. The agreement contains certain damage payment provisions if the purchases are not made by the specified date. The maximum pretax exposure under the agreement is currently estimated at approximately $100 million. In the fourth quarter of 2006, Duke Energy initiated early settlement discussions regarding this agreement and recorded a reserve of approximately $65 million during December of 2006 based upon probable penalty payments to be incurred. Future adjustments to this reserve could be material depending on the level of actual purchase commitments.

In October 2006, Duke Energy began an internal investigation into improper data reporting to the U.S. Environmental Protection Agency (USEPA) regarding air emissions under the NOx Budget Program at Duke Energy's DEGS of Narrows, L.L.C. power plant facility in Narrows, Virginia. The investigation has revealed evidence of falsification of data by an employee relating to the quality assurance testing of its continuous emissions monitoring system (CEMS) to monitor heat input and NOx emissions. In December 2006, Duke Energy voluntarily disclosed the potential violations to the USEPA and Virginia Department of Environmental Quality (VDEQ), and in January 2007, Duke Energy made a full written disclosure of the investigation's findings to the USEPA and the VDEQ. Duke Energy has taken appropriate disciplinary action, including termination, with respect to the employees involved with the false reporting. It is not possible to predict with certainty whether Duke Energy will incur any liability or to estimate the damages, if any, that Duke Energy might incur in connection with this matter.

Other. As part of its normal business, Duke Energy is a party to various financial guarantees, performance guarantees and other contractual commitments to extend guarantees of credit and other assistance to various subsidiaries, investees and other third parties. These arrangements are largely entered into by Duke Energy and Spectra Energy Capital. To varying degrees, these guarantees involve elements of performance and credit risk, which are not included on the Consolidated Balance Sheets. The possibility of Duke Energy or Spectra Energy Capital having to honor its contingencies is largely dependent upon future operations of various subsidiaries, investees and other third parties, or the occurrence of certain future events. (For further information see Note 18.)

In addition, Duke Energy enters into various fixed-price, non-cancelable commitments to purchase or sell power (tolling arrangements or power purchase contracts), take-or-pay arrangements, transportation or throughput agreements and other contracts that may or may not be recognized on the Consolidated Balance Sheets. Some of these arrangements may be recognized at market value on the Consolidated Balance Sheets as trading contracts or qualifying hedge positions included in Unrealized Gains or Losses on Mark-to-Market and Hedging Transactions. (See Note 18 for discussion of Calpine guarantee obligation).

Operating and Capital Lease Commitments

Duke Energy leases assets in several areas of its operations. Consolidated rental expense for operating leases was $146 million in 2006, $119 million in 2005 and $124 million in 2004, which is included in Operation, Maintenance and Other on the Consolidated Statements of Operations. Amortization of assets recorded under capital leases was included in Depreciation and Amortization on the Consolidated Statements of Operations. The following is a summary of future minimum lease payments under operating leases, which at inception had a noncancelable term of more than one year, and capital leases as of December 31, 2006:

	Operating Leases	Capital Leases
	(in millions)	
2007	$116	$ 11
2008	108	15
2009	94	16
2010	84	11
2011	59	9
Thereafter	257	32
Total future minimum lease payments	$718	$ 94

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

18. Guarantees and Indemnifications

Duke Energy and its subsidiaries have various financial and performance guarantees and indemnifications which are issued in the normal course of business. As discussed below, these contracts include performance guarantees, stand-by letters of credit, debt guarantees, surety bonds and indemnifications. Duke Energy and its subsidiaries enter into these arrangements to facilitate a commercial transaction with a third party by enhancing the value of the transaction to the third party.

In contemplation of the spin-off of the natural gas businesses on January 2, 2007 (see Note 1), certain guarantees that were previously issued by Spectra Energy Capital were transferred to Duke Energy prior to the consummation of the spin-off. Under FIN 45, guarantees that are modified after issuance are required to be remeasured at fair value at the date of modification. Accordingly, as a result of these modifications, Duke Energy recorded immaterial liability amounts in 2006 associated with these guarantees. Additionally, at December 31, 2006, Duke Energy has certain guarantees of wholly-owned subsidiaries that became guarantees of third party performance upon the spin-off of the natural gas businesses in January 2007. Duke Energy has received back-to-back indemnification from Spectra Energy Capital indemnifying Duke Energy for any amounts paid related to these guarantees.

Guarantees that were issued by or assigned to Duke Energy, Cinergy or International Energy on or prior to December 31, 2006 remained with Duke Energy subsequent to the spin-off. Guarantees issued by Spectra Energy Capital or Natural Gas Transmission on or prior to December 31, 2006 remained with Spectra Energy Capital subsequent to the spin-off, except for certain guarantees discussed below that are in the process of being assigned to Duke Energy. During this assignment period, Duke Energy has indemnified Spectra Energy Capital against any losses incurred under these guarantee obligations.

Duke Energy has issued performance guarantees to customers and other third parties that guarantee the payment and performance of other parties, including certain non-wholly owned entities. The maximum potential amount of future payments Duke Energy could have been required to make under these performance guarantees as of December 31, 2006 was approximately $27 million. Approximately $4 million of the performance guarantees expire in 2009, with the remaining performance guarantees having no contractual expiration.

Additionally, Duke Energy has issued guarantees to customers or other third parties related to the payment or performance obligations of certain entities that were previously wholly owned by Duke Energy but which have been sold to third parties, such as DukeSolutions, Inc. (DukeSolutions) and Duke Engineering & Services, Inc. (DE&S). These guarantees are primarily related to payment of lease obligations, debt obligations, and performance guarantees related to provision of goods and services. Duke Energy has received back-to-back indemnification from the buyer of DE&S indemnifying Duke Energy for any amounts paid by Spectra Energy Capital related to the DE&S guarantees. Duke Energy also received indemnification from the buyer of DukeSolutions for the first $2.5 million paid by Duke Energy related to the DukeSolutions guarantees. Further, Duke Energy granted indemnification to the buyer of DukeSolutions with respect to losses arising under some energy services agreements retained by DukeSolutions after the sale, provided that the buyer agreed to bear 100% of the performance risk and 50% of any other risk up to an aggregate maximum of $2.5 million (less any amounts paid by the buyer under the indemnity discussed above). Additionally, for certain performance guarantees, Duke Energy has recourse to subcontractors involved in providing services to a customer. These guarantees have various terms ranging from 2007 to 2019, with others having no specific term. The maximum potential amount of future payments under these guarantees as of December 31, 2006 was approximately $81 million.

Cinergy has issued performance guarantees to customers and other third parties that guarantee the payment and performance of certain non-wholly-owned consolidated entities. Additionally, Cinergy has issued guarantees of debt of certain non-consolidated entities and less than wholly owned consolidated entities. The maximum potential amount of future payments Cinergy could have been required to make under these performance guarantees as of December 31, 2006 was approximately $171 million. Approximately $92 million of the performance guarantees expire between 2008 and 2017, with the remaining performance guarantees having no contractual expiration.

Spectra Energy Capital has issued performance guarantees to customers and other third parties that guarantee the payment and performance of other parties, including certain non-wholly owned entities. The maximum potential amount of future payments Spectra Energy Capital could have been required to make under these performance guarantees as of December 31, 2006 was approximately $615 million, of which approximately $220 million is in the process of being assigned to Duke Energy, as discussed above. Of this amount, approximately $25 million relates to guarantees of the payment and performance of less than wholly owned consolidated entities. Approximately $40 million of the performance guarantees expire between 2007 and 2009, with the remaining performance guarantees expiring after 2009 or having no contractual expiration.

Additionally, Spectra Energy Capital has issued joint and several guarantees to some of the D/FD project owners, guaranteeing the performance of D/FD under its engineering, procurement and construction contracts and other contractual commitments Substantially all of these guarantees have no contractual expiration and no stated maximum amount of future payments that Spectra Energy Capital could be required to make Additionally, Fluor Enterprises Inc., as 50% owner in D/FD, has issued similar joint and several guarantees to the same D/FD project owners In accordance with the D/FD partnership agreement, each of the partners is responsible for 50% of any payments to be made under those guarantees

Westcoast has issued performance guarantees to third parties guaranteeing the performance of unconsolidated entities, such as equity method investments, and of entities previously sold by Westcoast to third parties. Those guarantees require Westcoast to make payment to the guaranteed third party upon the failure of such unconsolidated or sold entity to make payment under some of its contractual obligations, such as debt, purchase contracts and leases. The maximum potential amount of future payments Westcoast could have been required to make under those performance guarantees as of December 31, 2006 was approximately $15 million Of those guarantees, approximately $10 million expire in 2007, with the remainder having no contractual expiration.

Natural Gas Transmission and International Energy have issued guarantees of debt and performance guarantees associated with non-consolidated entities and less than wholly owned consolidated entities. If such entities were to default on payments or performance, Natural Gas Transmission or International Energy would be required under the guarantees to make payment on the obligation of the less than wholly owned entity. As of December 31, 2006, Natural Gas Transmission was the guarantor of approximately $17 million of debt at Westcoast associated with less than wholly owned entities, which expire in 2019. International Energy was the guarantor of approximately $13 million of performance guarantees associated with less than wholly owned entities. Substantially all of these guarantees expire between 2007 and 2008.

Duke Energy uses bank-issued stand-by letters of credit to secure the performance of non-wholly owned entities to a third party or customer Under these arrangements, Duke Energy has payment obligations to the issuing bank which are triggered by a draw by the third party or customer due to the failure of the non-wholly owned entity to perform according to the terms of its underlying contract. The maximum potential amount of future payments Duke Energy could have been required to make under these letters of credit as of December 31, 2006 was approximately $55 million. Substantially all of these letters of credit were issued on behalf of less than wholly owned consolidated entities and expire in 2007.

In connection with Duke Energy's sale of the Murray merchant generation facility to KGen, in August 2004, Duke Energy guaranteed in favor of a bank the repayment of any draws under a $120 million letter of credit issued by the bank to Georgia Power Company The letter of credit, which expires in 2007, is related to the obligation of a KGen subsidiary under a seven-year power sales agreement, commencing in May 2005. Duke Energy will be required to ensure reissuance of this letter of credit or issue similar credit support until the power sales agreement expires in 2012. Duke Energy will operate the sold Murray facility under an operation and maintenance agreement with the KGen subsidiary. As a result, the guarantee has an immaterial fair value. Further, KGen has agreed to indemnify Duke Energy for any payments Duke Energy makes with respect to the $120 million letter of credit. In February 2007, this guarantee was cancelled and Duke Energy has no future obligations associated with this matter.

Spectra Energy Capital has guaranteed certain issuers of surety bonds, obligating itself to make payment upon the failure of a non-wholly owned entity to honor its obligations to a third party As of December 31, 2006, Spectra Energy Capital had guaranteed approximately $210 million of outstanding surety bonds related to obligations of non-wholly owned entities. The majority of these bonds expire in various amounts in 2007 and 2008. Approximately $206 million of surety bonds were transferred to Duke Energy upon the consummation of the spin-off in January 2007.

In 1999, the Industrial Development Corp of the City of Edinburg, Texas (IDC) issued approximately $100 million in bonds to purchase equipment for lease to Duke Hidalgo (Hidalgo), a subsidiary of Duke Energy. Spectra Energy Capital unconditionally and irrevocably guaranteed the lease payments of Hidalgo to IDC through 2028. In 2000, Hidalgo was sold to Calpine Corporation and Spectra Energy Capital remained obligated under the lease guaranty. In January 2006, Hidalgo and its subsidiaries filed for bankruptcy protection in connection with the previous bankruptcy filing by its parent, Calpine Corporation in December 2005. Gross, undiscounted exposure under the guarantee obligation as of December 31, 2006 is approximately $200 million, including principal and interest payments. Duke Energy does not believe a loss under the guarantee obligation is probable as of December 31, 2006, but continues to evaluate the situation. Therefore, no reserves have been recorded for any contingent loss as of December 31, 2006 No demands for payment have been made under the guarantee. If losses are incurred under the guarantee, Spectra Energy Capital has certain rights which should allow it to miti —

gate such loss. Subsequent to the spin-off of the natural gas businesses, this guarantee remained with Spectra Energy Capital. However, Duke Energy indemnified Spectra Energy Capital against any future losses that could arise from payments required under this guarantee.

Duke Energy has entered into various indemnification agreements related to purchase and sale agreements and other types of contractual agreements with vendors and other third parties. These agreements typically cover environmental, tax, litigation and other matters, as well as breaches of representations, warranties and covenants. Typically, claims may be made by third parties for various periods of time, depending on the nature of the claim. Duke Energy's potential exposure under these indemnification agreements can range from a specified amount, such as the purchase price, to an unlimited dollar amount, depending on the nature of the claim and the particular transaction. Duke Energy is unable to estimate the total potential amount of future payments under these indemnification agreements due to several factors, such as the unlimited exposure under certain guarantees.

At December 31, 2006, the amounts recorded for the guarantees and indemnifications mentioned above are immaterial, both individually and in the aggregate.

19. Earnings Per Share (EPS)

Basic EPS is computed by dividing earnings available for common stockholders by the weighted-average number of common shares outstanding during the period. Diluted EPS is computed by dividing earnings available for common stockholders, as adjusted, by the diluted weighted-average number of common shares outstanding during the period. Diluted EPS reflects the potential dilution that could occur if securities or other agreements to issue common stock, such as stock options, stock-based performance unit awards, contingently convertible debt and phantom stock awards, were exercised, settled or converted into common stock.

The following tables illustrate Duke Energy's basic and diluted EPS calculations and reconcile the weighted-average number of common shares outstanding to the diluted weighted-average number of common shares outstanding for 2006, 2005, and 2004.

(in millions, except per share data)	Income	Average Shares	EPS
2006			
Income from continuing operations	$ 2,019		
Less: Dividends and premiums on redemption of preferred and preference stock	—		
Income from continuing operations—basic	2,019	1,170	$1.73
Effect of dilutive securities:			
Stock options, phantom, performance and restricted stock		4	
Contingently convertible bond	4	14	
Income from continuing operations—diluted	$ 2,023	1,188	$1.70
2005			
Income from continuing operations	$ 2,529		
Less: Dividends and premiums on redemption of preferred and preference stock	(12)		
Income from continuing operations—basic	2,517	934	$2.69
Effect of dilutive securities:			
Stock options, phantom, performance and restricted stock		4	
Contingently convertible bond	8	32	
Income from continuing operations—diluted	$ 2,525	970	$2.60
2004			
Income from continuing operations	$ 1,246		
Less: Dividends and premiums on redemption of preferred and preference stock	(9)		
Income from continuing operations—basic	1,237	931	$1.33
Effect of dilutive securities:			
Stock options, phantom, performance and restricted stock		2	
Contingently convertible bond	8	33	
Income from continuing operations—diluted	$ 1,245	966	$1.29

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

The increase in weighted-average shares outstanding for the year ended December 31, 2006 compared to the same period in 2005 was due primarily to the April 2006 issuance of approximately 313 million shares in conjunction with the merger with Cinergy (see Note 2), the conversion of debt into approximately 27 million shares of Duke Energy common stock during the year ended December 31, 2006 (see Note 21), and the repurchase and retirement of approximately 17.5 million shares of Duke Energy common stock during the year ended December 31, 2006 (see Note 21).

As of December 31, 2006, 2005 and 2004, approximately 14 million, 19 million and 23 million, respectively, of options, unvested stock, performance and phantom stock awards were not included in the "effect of dilutive securities" in the above table because either the option exercise prices were greater than the average market price of the common shares during those periods, or performance measures related to the awards had not yet been met.

20. Stock-Based Compensation

Effective January 1, 2006, Duke Energy adopted the provisions of SFAS No. 123(R). SFAS No. 123(R) establishes accounting for stock-based awards exchanged for employee and certain nonemployee services. Accordingly, for employee awards, equity classified stock-based compensation cost is measured at the grant date, based on the fair value of the award, and is recognized as expense over the requisite service period. Duke Energy previously applied Accounting Principles Board (APB) Opinion No. 25, "Accounting for Stock Issued to Employees," and FIN 44, "Accounting for Certain Transactions Involving Stock Compensation (an Interpretation of APB Opinion 25)" and provided the required pro forma disclosures of SFAS No. 123. Since the exercise price for all options granted under those plans was equal to the market value of the underlying common stock on the grant date, no compensation cost was recognized in the accompanying Consolidated Statements of Operations.

Duke Energy elected to adopt the modified prospective application method as provided by SFAS No. 123(R), and accordingly, financial statement amounts from the prior periods presented in this Form 10-K have not been restated. There were no modifications to outstanding stock options prior to the adoption of SFAS 123(R).

Duke Energy recorded pre-tax stock-based compensation expense for the years ended December 31, 2006, 2005 and 2004 as follows, the components of which are further described below:

	For the Years Ended December 31,		
	2006	2005	2004
	(in millions)		
Stock Options	$ 9	$ —	$ —
Stock Appreciation Rights	2	1	1
Phantom Stock	38	21	12
Performance Awards	30	24	12
Other Stock Awards	3	1	1
Total	$82	$ 47	$ 26

The tax benefit associated with the recorded expense for the year ended December 31, 2006, 2005 and 2004 was approximately $31 million, $17 million and $10 million, respectively. There were no material differences in income from continuing operations, income tax expense, net income, cash flows, or basic and diluted earnings per share from the adoption of SFAS No. 123(R).

The following table shows what earnings available for common stockholders, basic earnings per share and diluted earnings per share would have been if Duke Energy had applied the fair value recognition provisions of SFAS No. 123(R) to all stock-based compensation awards during prior periods.

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

Pro Forma Stock-Based Compensation

	Year ended December 31, 2005	Year ended December 31, 2004
	(in millions, except per share amounts)	
Earnings available for common stockholders, as reported	$ 1,812	$ 1,481
Add: stock-based compensation expense included in reported earnings available to common stockholders, net of related tax effects	30	16
Deduct: total stock-based compensation expense determined under fair value-based method for all awards, net of related tax effects	(32)	(27)
Pro forma earnings available for common stockholders, net of related tax effects	$ 1,810	$ 1,470
Earnings per share:		
Basic—as reported	$ 1.94	$ 1.59
Basic—pro forma	$ 1.94	$ 1.58
Diluted—as reported	$ 1.88	$ 1.54
Diluted—pro forma	$ 1.87	$ 1.53

Duke Energy's 2006 Long-term Incentive Plan (the 2006 Plan), approved by shareholders in October 2006, reserved 60 million shares of common stock for awards to employees and outside directors. Duke Energy's 1998 Long-term Incentive Plan, as amended (the 1998 Plan), reserved 60 million shares of common stock for awards to employees and outside directors. The 2006 Plan supersedes the 1998 Plan and no additional grants will be made from the 1998 Plan. Under the 2006 Plan and the 1998 Plan, the exercise price of each option granted cannot be less than the market price of Duke Energy's common stock on the date of grant and the maximum option term is 10 years. The vesting periods range from immediate to five years. Duke Energy has historically issued new shares upon exercising or vesting of share-based awards. In 2007, Duke Energy may use a combination of new share issuances and open market repurchases for share-based awards which are exercised or vested. Duke Energy has not determined with certainty the amount of such new share issuances or open market repurchases.

Upon the acquisition of Westcoast Energy, Inc (Westcoast), Duke Energy converted all stock options outstanding under the 1989 Westcoast Long-term Incentive Share Option Plan to Duke Energy stock options. Certain of these options also provide for share appreciation rights under which the holder of a stock option may, in lieu of exercising the option, exercise the share appreciation right. The exercise price of these options equals the market price on the date of grant and the maximum option term is 10 years. The vesting periods range from immediate to four years.

Upon the acquisition of Cinergy, Duke Energy converted all stock options outstanding under the Cinergy 1996 Long-Term Incentive Compensation Plan and Cinergy Corp. Stock Option Plan to Duke Energy stock options. The exercise price of these options equaled the market price on the date of grant and the maximum option term is 10 years. The vesting periods are generally three years. The 2006 Plan supersedes both Cinergy Plans and no additional grants will be made from these plans.

Stock Option Activity

	Options (in thousands)	Weighted-Average Exercise Price	Weighted-Average Remaining Life (in years)	Aggregate Intrinsic Value (in millions)
Outstanding at December 31, 2005	25,506	$ 29		
Granted[a]	9,173	24		
Exercised	(6,369)	23		
Forfeited or expired	(1,595)	34		
Outstanding at December 31, 2006	26,715	29	4.9	$ 173
Exercisable at December 31, 2006	21,923	$ 30	4.3	$ 122
Options Expected to Vest	4,744	$ 22	7.92	$ 51

(a) Includes 7,294,994 converted Cinergy stock options.

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

On December 31, 2005 and 2004, Duke Energy had approximately 22 million exercisable options with a $32 weighted-average exercise price. The total intrinsic value of options exercised during the years ended December 31, 2006, 2005 and 2004 was approximately $46 million, $17 million and $7 million, respectively. Cash received from options exercised during the year ended December 31, 2006 was approximately $127 million, with a related tax benefit of approximately $17 million. At December 31, 2006, Duke Energy had approximately $7 million of future compensation cost which is expected to be recognized over a weighted-average period of 1.5 years.

In addition to the conversion of the Cinergy stock options noted above, Duke Energy granted 1,877,646 options (fair value of approximately $10 million based on a Black-Scholes model valuation) during the year ended December 31, 2006. There were no options granted during the years ended December 31, 2005 and 2004. Remaining compensation expense to be recognized for unvested converted Cinergy options was determined using a Black-Scholes model.

Weighted-Average Assumptions for Option Pricing

	2006
Risk-free interest rate(1)	4.78%
Expected dividend yield(2)	4.40%
Expected life(3)	6.29 yrs.
Expected volatility(4)	24%

(1) The risk free rate is based upon the U.S. Treasury Constant Maturity rates as of the grant date.

(2) The expected dividend yield is based upon annualized dividends and the 1-year average closing stock price.

(3) The expected term of options is derived from historical data.

(4) Volatility is based upon 50% historical and 50% implied volatility. Historic volatility is based on the weighted average between Duke and Cinergy historical volatility over the expected life using daily stock prices. Implied volatility is the average for all option contracts with a term greater than six months using the strike price closest to the stock price on the valuation date.

The 2006 Plan allows for a maximum of 15 million shares of common stock to be issued under various stock-based awards other than options and stock appreciation rights. The 1998 Plan allows for a maximum of 12 million shares of common stock to be issued under various stock-based awards. Payments for cash settled awards during the period were immaterial.

Performance Awards

Stock-based performance awards outstanding under the 1998 Plan generally vest over three years. Vesting for certain stock-based performance awards can occur in three years, at the earliest, if performance is met. Certain performance awards granted in 2006 contain market conditions based on the total shareholder return (TSR) of Duke Energy stock relative to a pre-defined peer group (relative TSR). These awards are valued using a path-dependent model that incorporates expected relative TSR into the fair value determination of Duke Energy's performance-based share awards with the adoption of SFAS No. 123(R). The model uses three year historical volatilities and correlations for all companies in the pre-defined peer group, including Duke Energy, to simulate Duke Energy's relative TSR as of the end of the performance period. For each simulation, Duke Energy's relative TSR associated with the simulated stock price at the end of the performance period plus expected dividends within the period results in a value per share for the award portfolio. The average of these simulations is the expected portfolio value per share. Actual life to date results of Duke Energy's relative TSR for each grant is incorporated within the model. Other awards not containing market conditions are measured at grant date price. Duke Energy awarded 1,610,350 shares (fair value of approximately $32 million) in the year ended December 31, 2006, 1,275,020 shares (fair value of approximately $34 million, based on the market price of Duke Energy's common stock at the grant date) in the year ended December 31, 2005, and 1,584,840 shares (fair value of approximately $34 million, based on the market price of Duke Energy's common stock at the grant date) in the year ended December 31, 2004.

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

The following table summarizes information about stock-based performance awards outstanding at December 31, 2006:

	Shares	Weighted Average Grant Date Fair Value
Number of Stock-based Performance Awards:		
Outstanding at December 31, 2005	2,940,768	$ 25
Granted	1,610,350	20
Vested	(114,000)	27
Forfeited	(310,838)	26
Canceled	—	—
Outstanding at December 31, 2006	4,126,280	$ 23
Stock-based Performance Awards Expected to Vest	3,955,865	$ 23

The total fair value of the shares vested during the year ended December 31, 2006 and 2005 was approximately $3 million. As of December 31, 2006, Duke Energy had approximately $31 million of future compensation cost which is expected to be recognized over a weighted-average period of 1.0 years.

Phantom Stock Awards

Phantom stock awards outstanding under the 1998 Plan generally vest over periods from immediate to five years. Duke Energy awarded 1,181,370 shares (fair value of approximately $34 million) based on the market price of Duke Energy's common stock at the grant dates in the year ended December 31, 2006, 1,139,880 shares (fair value of approximately $31 million) in the year ended December 31, 2005, and 1,283,220 shares (fair value of approximately $27 million) in the year ended December 31, 2004. Converted Cinergy phantom stock awards are paid in cash and are measured and recorded as liability awards.

The following table summarizes information about phantom stock awards outstanding at December 31, 2006:

	Shares	Weighted Average Grant Date Fair Value
Number of Phantom Stock Awards:		
Outstanding at December 31, 2005	2,517,020	$ 25
Granted(b)	1,213,532	29
Vested	(917,441)	25
Forfeited	(200,791)	26
Canceled	—	—
Outstanding at December 31, 2006	2,612,320	$ 27
Phantom Stock Awards Expected to Vest	2,507,432	$ 27

(b) Includes 32,162 converted Cinergy awards.

The total fair value of the shares vested during the years ended December 31, 2006, 2005 and 2004 was approximately $23 million, $10 million and $7 million, respectively. As of December 31, 2006, Duke Energy had approximately $24 million of future compensation cost which is expected to be recognized over a weighted-average period of 3.0 years

Other Stock Awards

Other stock awards outstanding under the 1998 Plan generally vest over periods from three to five years. Duke Energy awarded 279,000 shares (fair value of approximately $8 million) based on the market price of Duke Energy's common stock at the grant dates in the year ended December 31, 2006, 47,000 shares (fair value of approximately $1 million) in the year ended December 31, 2005, and 169,160 shares (fair value of approximately $4 million) in the year ended December 31, 2004.

The following table summarizes information about other stock awards outstanding at December 31, 2006:

	Shares	Weighted Average Grant Date Fair Value
Number of Other Stock Awards:		
Outstanding at December 31, 2005	178,337	$ 25
Granted[(c)]	329,980	28
Vested	(71,610)	26
Forfeited	(10,200)	33
Canceled	—	—
Outstanding at December 31, 2006	426,507	$ 28
Other Stock Awards Expected to Vest	395,671	$ 28

(c) Includes 50,980 converted Cinergy awards

The total fair value of the shares vested during the years ended December 31, 2006, 2005 and 2004 was approximately $2 million, $1 million and $1 million, respectively. As of December 31, 2006, Duke Energy had approximately $8 million of future compensation cost which is expected to be recognized over a weighted-average period of 2.9 years.

21. Common Stock

During 2006, Duke Energy's $742 million of convertible debt became convertible into approximately 31.7 million shares of Duke Energy common stock due to the market price of Duke Energy common stock achieving a specified threshold for each pricing period prior to respective quarter. Holders of the convertible debt were able to exercise their right to convert on or prior to each quarter end. During 2006, approximately $632 million of debt was converted into approximately 26.7 million shares of Duke Energy common stock. At December 31, 2006, the balance of the convertible debt is approximately $110 million, which is convertible into approximately 4.7 million shares of common stock.

See Note 1 for discussion of 313 million shares of common stock issued in April 2006 as a result of the merger with Cinergy

Effective in the third quarter 2006, the Board of Directors of Duke Energy approved a quarterly dividend increase of $0.01 per share, increasing the annual dividend to $1.28 per share.

In February 2005, Duke Energy announced plans to execute up to approximately $2.5 billion in common stock repurchases over a three year period. In May 2005, Duke Energy suspended additional repurchases, pending further assessment. At the time of suspension, Duke Energy had repurchased approximately $933 million of common stock. In the first quarter of 2006, as a result of the March 10, 2006 shareholder approval of the Cinergy merger, Duke Energy's Board of Directors authorized the repurchase of up to an additional $1 billion of common stock under the previously announced share repurchase plan. In June 2006, Duke Energy suspended additional repurchases of Duke Energy common stock under the repurchase plan due to its plan to spin off the natural gas businesses (see Note 25). Prior to the June 2006 suspension, Duke Energy repurchased 17.5 million shares for total consideration of approximately $500 million during 2006. The repurchases and corresponding commissions and other fees were recorded in Common Stockholders' Equity as a reduction in Common Stock and Additional Paid-in Capital. In October 2006, Duke Energy's Board of Directors authorized the reactivation of the share repurchase plan for Duke Energy of up to $500 million of share repurchases after the spin-off of the natural gas businesses has been completed.

On March 18, 2005, Duke Energy entered into an accelerated share repurchase transaction whereby Duke Energy repurchased and retired 30 million shares of its common stock from an investment bank at the March 18, 2005 closing price of $27.46 per share. Total consideration paid to repurchase the shares of approximately $834 million, including approximately $10 million in commissions and other fees, was recorded in Common Stockholders' Equity as a reduction in Common Stock. Additionally, Duke Energy entered into a separate open-market purchase plan on March 18, 2005 to repurchase up to an additional 20 million shares of its common stock, of which approximately 2.6 million shares were repurchased prior to the May 2005 suspension of the program at a weighted average price of $28.97

per share. As part of the accelerated share repurchase transaction, Duke Energy simultaneously entered into a forward sale contract with the investment bank that was to mature no later than November 8, 2005. Under the terms of the forward sale contract, the investment bank was required to purchase, in the open market, 30 million shares of Duke Energy common stock during the term of the contract to fulfill its obligation related to the shares it borrowed from third parties and sold to Duke Energy. At settlement, Duke Energy, at its option, was required to either pay cash or issue registered or unregistered shares of its common stock to the investment bank if the investment bank's weighted average purchase price was higher than the March 18, 2005 closing price of $27.46 per share, or the investment bank was required to pay Duke Energy either cash or shares of Duke Energy common stock, at Duke Energy's option, if the investment bank's weighted average price for the shares purchased was lower than the March 18, 2005 closing price of $27.46 per share. On September 22, 2005, Duke Energy, at its option, paid approximately $25 million in cash to the investment bank to settle the forward sale contract as the investment bank had repurchased the full 30 million shares in the open market and fulfilled all of its obligations. The amount paid to the investment bank was based upon the difference between the investment bank's weighted average price paid for the 30 million shares purchased of $28.42 per share and the March 18, 2005 closing price of $27.46 per share. Duke Energy recorded the approximately $25 million paid at settlement in Common Stockholders' Equity as a reduction in Common Stock. Total consideration paid to repurchase the shares of approximately $933 million, including commissions and other fees, was recorded in Common Stockholders' Equity as a reduction in Common Stock and Additional Paid-in Capital.

In November 2004, Duke Energy issued 18,693,000 shares of its common stock in the settlement of the forward-purchase contract component of its Equity Units issued in November 2001. Under the terms of the contract, the Equity Unit holders were required to purchase stock at the time of settlement rate based on the current market price of Duke Energy's common stock at the time of the settlement with a floor and a ceiling. The rate was .6231 shares of stock per Equity Unit. Duke Energy received $750 million in proceeds as a result of the settlement, which was included in Proceeds from the Issuances of Common Stock and Common Stock Related to Employee Benefit Plans on the Consolidated Statement of Cash Flows.

In May 2004, Duke Energy issued 22,449,000 shares of its common stock in the settlement of the forward-purchase contract component of its Equity Units issued in March 2001. Under the terms of the contract, the Equity Unit holders were required to purchase common stock at a settlement rate based on the current market price of Duke Energy's common stock at the time of settlement with a floor and a ceiling. The rate was 0.6414 shares of stock per Equity Unit. Duke Energy received $875 million in proceeds as a result of the settlement, which was included in Proceeds from the Issuances of Common Stock and Common Stock Related to Employee Benefit Plans on the Consolidated Statement of Cash Flows.

Duke Energy also sponsors an employee savings plan that covers substantially all U.S. employees. In April 2004, Duke Energy stopped issuing shares under the plan and the plan began making open market purchases with cash provided by Duke Energy. There were no issuances of common stock under the plan in either 2006 or 2005. Issuances of common stock under the plan were $51 million in 2004. Duke Energy also issues shares of its common stock to meet other employee benefit requirements. Issuances of common stock to meet other employee benefit requirements were approximately $146 million for 2006, $39 million for 2005 and approximately $12 million for 2004.

See the Consolidated Statements of Common Stockholders' Equity and Comprehensive Income (Loss) for additional equity transactions.

22. Employee Benefit Plans

Duke Energy U.S. Retirement Plans. Duke Energy and its subsidiaries (including legacy Cinergy businesses) maintain qualified, non-contributory defined benefit retirement plans. The plans cover most U.S. employees using a cash balance formula. Under a cash balance formula, a plan participant accumulates a retirement benefit consisting of pay credits that are based upon a percentage (which may vary with age and years of service) of current eligible earnings and current interest credits. Certain legacy Cinergy U.S. employees are covered under plans that use a final average earnings formula. Under a final average earnings formula, a plan participant accumulates a retirement benefit equal to a percentage of their highest 3-year average earnings, plus a percentage of the their highest 3-year average earnings in excess of covered compensation per year of participation (maximum of 35 years), plus a percentage of their highest 3-year average earnings times years of participation in excess of 35 years.

Duke Energy also maintains non-qualified, non-contributory defined benefit retirement plans which cover certain U.S. executives.

Duke Energy's policy is to fund amounts on an actuarial basis to provide assets sufficient to meet benefits to be paid to plan participants. Duke Energy contributed approximately $124 million to the legacy Cinergy qualified pension plans in 2006. Duke Energy did not make any contributions to its defined benefit retirement plans in 2005. Duke Energy made voluntary contributions of $250 million in the fourth quarter of 2004.

Actuarial gains and losses are amortized over the average remaining service period of the active employees. The average remaining service period of active employees covered by the qualified retirement plans is 11 years. The average remaining service period of active employees covered by the non-qualified retirement plans is 8 years. Duke Energy determines the market-related value of plan assets using a calculated value that recognizes changes in fair value of the plan assets in a particular year on a straight line basis over the next five years. Duke Energy uses a September 30 measurement date for its defined benefit retirement plans.

Westcoast Canadian Retirement Plans. The Westcoast benefit plans are reported separately due to actuarial assumption differences. Westcoast and its subsidiaries maintain qualified and non-qualified contributory and non-contributory defined benefit (DB) and defined contribution (DC) retirement plans covering substantially all employees. The DB plans provide retirement benefits based on each plan participant's years of service and final average earnings. Under the DC plans, company contributions are determined according to the terms of the plan and based on each plan participant's age, years of service and current eligible earnings. Westcoast also provides non-registered defined benefit supplemental pensions to all employees who retire under a defined benefit registered pension plan and whose pension is limited by the maximum pension limits under the Income Tax Act (Canada).

Westcoast's policy is to fund the DB plans on an actuarial basis and in accordance with Canadian pension standards legislation, in order to accumulate assets sufficient to meet benefits to be paid. Contributions to the DC plans are determined in accordance with the terms of the plan. Duke Energy made contributions to the Westcoast DB plans of approximately $44 million in 2006, $42 million in 2005 and $26 million in 2004. Duke Energy also made contributions to the DC plans of $4 million in 2006, $3 million in 2005 and $3 million in 2004.

The prior service cost and actuarial gains and losses are amortized over the average remaining service period of the active employees. The average remaining service period of the active employees covered by the qualified DB retirement plans is 10 years. The average remaining service period of the active employees covered by the non-qualified DB retirement plan is 14 years. Westcoast uses a September 30 measurement date for its plans.

Duke Energy adopted the disclosure and recognition provisions of SFAS No. 158, effective December 31, 2006. The following table describes the total incremental effect of the adoption of SFAS No. 158 on individual line items in the December 31, 2006 Consolidated Balance Sheet, including Accumulated Other Comprehensive Income.

Incremental Effect of the Adoption of SFAS No. 158 on Individual Line Items in the Consolidated Balance Sheet As of December 31, 2006 [a]

	Duke Energy U.S.			Westcoast		
	Before Application of SFAS No. 158	Adjustment	After Application of SFAS No. 158[b]	Before Application of SFAS No. 158	Adjustment	After Application of SFAS No. 158
	(in millions)					
Accrued pension and other post-retirement liabilities[(c)]	$(1,562)	$ (385)	$ (1,947)	$(223)	$ (69)	$ (292)
Intangible assets	—	—	—	6	(6)	—
Pre-funded pension costs	697	(522)	175	—	—	—
Regulatory assets	—	595	595	—	—	—
Deferred income tax assets	—	115	115	32	27	59
Accumulated other comprehensive income, net of tax	—	197	197	61	48	109
Total Recognized	$ (865)	$ —	$ (865)	$(124)	$ —	$ (124)

(a) Excludes approximately $7 million in accrued pension and other post-retirement liabilities, approximately $2 million in deferred income tax assets and $5 million in accumulated other comprehensive income associated with a Brazilian retirement plan.

(b) Includes approximately $87 million in accrued pension and other post-retirement liabilities and $4 million in accumulated other comprehensive income related to delayed recognition provisions associated with post-employment benefits.

(c) Includes approximately $89 million that is reflected in Other within Current Liabilities in the Consolidated Balance Sheets at December 31, 2006.

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

Qualified Pension Plans

Components of Net Periodic Pension Costs (Income): Qualified Pension Plans

	Duke Energy U.S.			Westcoast		
	For the Years Ended December 31,					
	2006	2005	2004	2006	2005	2004
	(in millions)					
Service cost benefit earned during the year	$ 93	$ 61	$ 64	$ 13	$ 9	$ 8
Interest cost on projected benefit obligation	207	157	160	31	29	26
Expected return on plan assets	(275)	(229)	(233)	(33)	(27)	(24)
Amortization of prior service cost	(1)	(1)	(2)	1	1	—
Amortization of net transition asset	—	—	(4)	—	—	—
Curtailment (gain) / loss	—	—	(1)	—	—	—
Amortization of loss	54	35	15	10	4	3
Special termination benefit cost	2	—	—	—	—	1
Net periodic pension costs / (income)	$ 80	$ 23	$ (1)	$ 22	$ 16	$ 14

Reconciliation of Funded Status to Net Amount Recognized: Qualified Pension Plans

	Duke Energy U.S.		Westcoast	
	As of and for the Years Ended December 31,			
	2006	2005	2006	2005
	(in millions)			
Change in Projected Benefit Obligation				
Obligation at prior measurement date	$2,853	$2,693	$616	$ 480
Service cost	93	61	13	9
Interest cost	207	157	31	29
Actuarial losses / (gains)	42	105	20	89
Plan amendments	19	—	—	—
Participant contributions	—	—	3	3
Benefits paid	(263)	(163)	(32)	(28)
Obligation assumed from acquisition	1,872	—	—	11
Foreign currency impact	—	—	2	23
Obligation at measurement date	$4,823	$2,853	$653	$ 616

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

	Duke Energy U.S.		Westcoast	
	As of and for the Years Ended December 31,			
	2006	2005	2006	2005
	(in millions)			
Change In Fair Value of Plan Assets				
Plan assets at prior measurement date	$2,948	$2,477	$475	$ 362
Actual return on plan assets	316	384	32	63
Benefits paid	(263)	(163)	(32)	(28)
Employer contributions	124	250	45	48
Plan participants' contributions	—	—	3	3
Assets received on acquisition	1,199	—	—	10
Foreign currency impact	—	—	2	17
Plan assets at measurement date	$4,324	$2,948	$525	$ 475
Funded status	$ (499)	$ 95	$(128)	$ (141)
Unrecognized net experience loss	—	655	—	122
Unrecognized prior service cost	—	(3)	—	8
Contributions between measurement date and year end	—	—	12	13
Net amount recognized	$ (499)	$ 747	$(116)	$ 2

For the Duke Energy U S. plans, the accumulated benefit obligation was $4,408 million at September 30, 2006 and $2,753 million at September 30, 2005.

For Westcoast, the accumulated benefit obligation was $588 million at September 30, 2006 and $562 million at September 30, 2005

Qualified Pension Plans—Amounts Recognized in the Consolidated Balance Sheets

Consist of:

	Duke Energy U.S.		Westcoast	
	As of December 31,			
	2006	2005	2006	2005
	(in millions)			
Accrued pension liability	$(674)	$ —	$(116)	$ (76)
Intangible asset	—	—	—	7
Pre-funded pension costs	175	747	—	—
Deferred income tax asset	—	—	—	25
Accumulated other comprehensive income	—	—	—	46
Net amount recognized	$(499)	$ 747	$(116)	$ 2

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

As a result of the adoption of SFAS No 158, certain previously unrecognized amounts were recognized in the amounts noted above with an offset to Accumulated Other Comprehensive Income, Deferred Income Taxes and Regulatory Assets as of December 31, 2006 The table below details the components of these balances

Qualified Pension Plans—Amounts Recognized in Regulatory Assets and Accumulated Other Comprehensive Income

Consist of:

	Duke Energy U.S.	Westcoast
	As of December 31, 2006	
	(in millions)	
Regulatory assets	$481	$ —
Accumulated other comprehensive income		
Deferred income tax asset	$ (50)	$ (49)
Net transition obligation	—	—
Prior service cost	10	8
Net actuarial loss	126	132
Net amount recognized – Accumulated other comprehensive income	$ 86	$ 91

Qualified Pension Plans—Amounts in Regulatory Assets and Accumulated Other Comprehensive Income

***to be Recognized in Net Periodic Pension Costs in 2007* Consist of:**

	Duke Energy U.S.
	(in millions)
Unrecognized (gains)/losses	$ 42
Unrecognized prior service cost	—
Net amount to be recognized	$ 42

Amounts in the above table exclude Westcoast due to the spin-off of the natural gas businesses on January 2, 2007

Additional Information:

Qualified Pension Plans—Information for Plans with Accumulated Benefit Obligation in Excess of Plan Assets

	Duke Energy U.S.		Westcoast	
	As of December 31,			
	2006	2005	2006	2005
	(in millions)			
Projected benefit obligation	$1,976	$ —	$637	$ 602
Accumulated benefit obligation	1,688	—	576	551
Fair value of plan assets	1,302	—	511	464

Qualified Pension Plans—Assumptions Used for Pension Benefits Accounting

Benefit Obligations	Duke Energy U.S. 2006	2005	2004	Westcoast 2006	2005	2004
	(percentages)					
Discount rate	5.75	5.50	6.00	5.00	5.00	6.25
Salary increase	5.00	5.00	5.00	3.50	3.25	3.25

Determined Expense	2006	2005	2004	2006	2005	2004
Discount rate	5.50–6.00	6.00	6.00	5.00	6.25	6.00
Salary increase	5.00	5.00	5.00	3.25	3.25	3.25
Expected long–term rate of return on plan assets	8.50	8.50	8.50	7.25	7.50	7.50

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

For the Duke Energy U.S. plans the discount rate used to determine the pension obligation is based on a AA bond yield curve. The yield is selected based on bonds with cash flows that match the timing and amount of the expected benefit payments under the plan. For legacy Cinergy plans, the discount rate used to determine expense reflects remeasurement as of April 1, 2006 due to the merger between Duke Energy and Cinergy.

For Westcoast the discount rate used to determine the pension obligation is prescribed as the yield on Canadian corporate AA bonds at the measurement date of September 30. The yield is selected based on bonds with cash flows that match the timing and amount of the expected benefit payments under the plan.

Qualified Pension Plan Assets—Duke Energy U.S.:

Asset Category	Target Allocation	Percentage of Plan Assets at September 30 2006	2005
U.S. equity securities	46%	46%	46%
Non-U.S. equity securities	18	19	21
Debt securities	32	32	29
Real estate	4	3	4
Total	100%	100%	100%

Duke Energy U.S. assets for both the pension and other post retirement benefits are maintained by two Master Trusts. The investment objective of the master trusts is to achieve reasonable returns on trust assets, subject to a prudent level of portfolio risk, for the purpose of enhancing the security of benefits for plan participants. The asset allocation targets were set after considering the investment objective and the risk profile with respect to the trusts. U.S. equities are held for their high expected return. Non-U.S. equities, debt securities, and real estate are held for diversification. Investments within asset classes are to be diversified to achieve broad market participation and reduce the impact of individual managers or investments. Duke Energy regularly reviews its actual asset allocation and periodically rebalances its investments to the targeted allocation when considered appropriate.

The long-term rate of return of 8.5% as of September 30, 2006 for the Duke Energy U.S. assets was developed using a weighted-average calculation of expected returns based primarily on future expected returns across classes considering the use of active asset managers. The weighted-average returns expected by asset classes were 4.2% for U.S. equities, 1.8% for Non-U.S. equities, 2.2% for fixed income securities, and 0.3% for real estate.

Qualified Pension Plan Assets—Westcoast:

Asset Category	Target Allocation	Percentage of Plan Assets at September 30 2006	2005
Canadian equity securities	30%	29%	42%
U.S. equity securities	15	15	11
EAFE equity securities[(a)]	15	16	15
Debt securities	40	40	32
Total	100%	100%	100%

(a) EAFE—Europe, Australasia, Far East

Westcoast assets for registered pension plans are maintained by a Master Trust. The investment objective of the master trust is to achieve reasonable returns on trust assets, subject to a prudent level of portfolio risk, for the purpose of enhancing the security of benefits for participants. The asset allocation targets were set after considering the investment objective and the risk profile with respect to the trust. Canadian equities are held for their high expected return. Non-Canadian equities are held for their high expected return as well as diversification relative to Canadian equities and debt securities. Debt securities are also held for diversification.

The long-term rate of return of 7.25% as of September 30, 2006 for the Westcoast assets was developed using a weighted-average calculation of expected returns based primarily on future expected returns across classes considering the use of active asset managers.

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

The weighted-average returns expected by asset classes were 2 5% for Canadian equities, 1 3% for U.S. equities, 1 4% for Europe, Australasia and Far East equities, and 2 0% for fixed income securities

The following benefit payments, which reflect expected future service, as appropriate, as expected to be paid over the next five years and thereafter:

Qualified Pension Plans—Expected Benefit Payments

	U.S. Plans	Westcoast Plans
	(in millions)	
Years Ended December 31,		
2007	$ 311	$ 31
2008	309	31
2009	323	32
2010	342	33
2011	377	34
2012 – 2016	2,101	201

Non-Qualified Pension Plans

Components of Net Periodic Pension Costs: Non-Qualified Pension Plans

	Duke Energy U.S.			Westcoast		
	For the Years Ended December 31,					
	2006	2005	2004	2006	2005	2004
	(in millions)					
Service cost benefit earned during the year	$ 2	$ 1	$ 2	$ 1	$ 1	$ —
Interest cost on projected benefit obligation	8	5	6	4	4	4
Expected return on plan assets	—	—	—	—	—	—
Amortization of prior service cost	1	1	1	—	—	—
Amortization of net transition (asset)/liability	—	1	1	—	—	—
Curtailment (gain) / loss	—	—	1	—	—	—
Amortization of loss	—	—	—	1	—	—
Net periodic pension costs / (income)	$11	$ 8	$ 11	$ 6	$ 5	$ 4

Reconciliation of Funded Status to Net Amount Recognized: Non-Qualified Pension Plans

	Duke Energy U.S.		Westcoast	
	As of and for the Years Ended December 31,			
	2006	2005	2006	2005
	(in millions)			
Change in Projected Benefit Obligation				
Obligation at prior measurement date	$ 86	$ 86	$84	$ 66
Service cost	2	1	1	1
Interest cost	8	5	4	4
Actuarial losses / (gains)	4	2	3	14
Plan amendments	(2)	—	—	—
Participant contributions	—	—	—	—
Benefits paid	(36)	(8)	(4)	(3)

Obligation assumed from acquisition	137	—	—	—
Foreign currency impact	—	—	—	2
Obligation at measurement date	$199	$ 86	$88	$ 84

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

	Duke Energy U.S.		Westcoast	
	As of and for the Years Ended December 31,			
	2006	2005	2006	2005
	(in millions)			
Change in Fair Value of Plan Assets				
Plan assets at prior measurement date	$ —	$ —	$ —	$ —
Actual return on plan assets	—	—	—	—
Benefits paid	(36)	(8)	(4)	(3)
Employer contributions	36	8	4	3
Plan participants' contributions	—	—	—	—
Assets received on acquisition	—	—	—	—
Foreign currency impact	—	—	—	—
Plan assets at measurement date	$ —	$ —	$ —	$ —
Funded status	$(199)	$ (86)	$(88)	$ (84)
Unrecognized net experience loss	—	(7)	—	23
Unrecognized prior service cost	—	8	—	—
Contributions between measurement date and year end	21	2	2	1
Accrued pension liability	$(178)	$ (83)	$(86)	$ (60)

For the Duke Energy U.S. plans, the accumulated benefit obligation was $184 million at September 30, 2006 and $79 million at September 30, 2005.

For Westcoast, the accumulated benefit obligation was $83 million at September 30, 2006 and $82 million at September 30, 2005.

Non-Qualified Pension Plans—Amounts Recognized in the Consolidated Balance Sheets

Consist of:

	Duke Energy U.S.		Westcoast	
	As of December 31,			
	2006	2005	2006	2005
	(in millions)			
Accrued pension liability[a]	$(178)	$ (83)	$(86)	(81)
Pre-funded pension costs	—	—	—	—
Accumulated other comprehensive income	—	—	—	21
Net amount recognized	$(178)	$ (83)	$(86)	$ (60)

(a) Duke Energy U.S. includes approximately $41 million and Westcoast includes approximately $6 million recognized in Other within Current Liabilities on the Consolidated Balance Sheets as of December 31, 2006.

As a result of the adoption of SFAS No. 158, certain previously unrecognized amounts were recognized in the amounts noted above with an offset to Accumulated Other Comprehensive Income, Deferred Income Taxes and Regulatory Assets as of December 31, 2006. The table below details the components of these balances.

Non-Qualified Pension Plans—Amounts Recognized in Regulatory Assets and Accumulated Other Comprehensive Income

Consist of:

	Duke Energy U.S.	Westcoast
	As of December 31, 2006	
	(in millions)	
Regulatory assets	$ 4	$ —
Accumulated other comprehensive income		
Deferred income tax liability (asset)	$ 1	$ (9)
Net transition obligation	—	—
Prior service cost	5	—
Net actuarial loss	(7)	25
Net amount recognized– Accumulated other comprehensive income	$(1)	$ 16

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

Non-Qualified Pension Plans—Amounts in Regulatory Assets and Accumulated Other Comprehensive Income to be Recognized in Net Periodic Pension Costs in 2007 Consist of:

	Duke Energy U.S.
	(in millions)
Unrecognized (gains)/losses	$ —
Unrecognized prior service cost	2
Net amount to be recognized	$ 2

Amounts in the above table exclude Westcoast due to the spin-off of the natural gas businesses on January 2, 2007.

Additional Information:

Non-Qualified Pension Plans—Information for Plans with Accumulated Benefit Obligation in Excess of Plan Assets

	Duke Energy U.S.		Westcoast	
	As of December 31,			
	2006	2005	2006	2005
	(in millions)			
Projected benefit obligation	$199	$ 86	$88	$ 84
Accumulated benefit obligation	184	79	83	82
Fair value of plan assets	—	—	—	—

Non-Qualified Pension Plans—Assumptions Used for Pension Benefits Accounting

	Duke Energy U.S.			Westcoast		
Benefit Obligations	2006	2005	2004	2006	2005	2004
	(percentages)					
Discount rate	5.75	5.50	6.00	5.00	5.00	6.25
Salary increase	5.00	5.00	5.00	3.50	3.25	3.25
Determined Expense	2006	2005	2004	2006	2005	2004
Discount rate	5.50-6.00	6.00	6.00	5.00	6.25	6.00
Salary increase	5.00	5.00	5.00	3.25	3.25	3.25

For the Duke Energy U.S. plans the discount rate used to determine the pension obligation is based on a AA bond yield curve. The yield is selected based on bonds with cash flows that match the timing and amount of the expected benefit payments under the plan. For legacy Cinergy plans, the discount rate used to determine expense reflects remeasurement as of April 1, 2006 due to the merger between Duke Energy and Cinergy.

For Westcoast the discount rate used to determine the pension obligation is prescribed as the yield on Canadian corporate AA bonds at the measurement date of September 30. The yield is selected based on bonds with cash flows that match the timing and amount of the expected benefit payments under the plan.

Non-Qualified Plans—Expected Benefit Payments

	U.S. Plans	Westcoast Plans
	(in millions)	
Years Ended December 31,		
2007	$41	$ 5
2008	16	5
2009	20	5
2010	16	5
2011	16	5
2012 – 2016	66	26

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

Duke Energy also sponsors employee savings plans that cover substantially all U.S. employees. Most employees participate in a matching contribution formula where Duke Energy provides a matching contribution generally equal to 100% of before-tax employee contributions, of up to 6% of eligible pay per pay period. Duke Energy expensed employer matching contributions of $75 million in 2006, $61 million in 2005 and $57 million in 2004. Dividends on Duke Energy shares held by the savings plans are charged to retained earnings when declared and shares held in the plans are considered outstanding in the calculation of basic and diluted earnings per share.

Other Post-Retirement Benefit Plans

Duke Energy U.S. Other Post-Retirement Benefits. Duke Energy and most of its subsidiaries provide some health care and life insurance benefits for retired employees on a contributory and non-contributory basis. Employees are eligible for these benefits if they have met age and service requirements at retirement, as defined in the plans.

These benefit costs are accrued over an employee's active service period to the date of full benefits eligibility. The net unrecognized transition obligation is amortized over approximately 20 years. Actuarial gains and losses are amortized over the average remaining service period of the active employees. The average remaining service period of the active employees covered by the plan is 13 years.

Westcoast Other Post-Retirement Benefits. Westcoast provides health care and life insurance benefits for retired employees on a non-contributory basis. Employees are eligible for these benefits if they have met age and service requirements at retirement, as defined in the plans. Effective December 31, 2003, a new plan was implemented for all non bargaining employees and the majority of bargaining employees. The new plan will apply for employees retiring on and after January 1, 2006. The new plan is predominantly a defined contribution plan as compared to the existing defined benefit program.

Other post-retirement benefit costs are accrued over an employee's active service period to the date of full benefits eligibility. Actuarial gains and losses are amortized over the average remaining service period of the active employees covered by the plans. The average remaining service period of the active employees is 18 years.

Components of Net Periodic Other Post-Retirement Benefit Costs

	Duke Energy U.S.			Westcoast		
	For the Years Ended December 31,					
	2006	2005	2004	2006	2005	2004
	(in millions)					
Service cost benefit earned during the year	$ 10	$ 6	$ 5	$ 4	$ 3	$ 3
Interest cost on accumulated post-retirement benefit obligation	56	45	47	7	6	5
Expected return on plan assets	(17)	(18)	(19)	—	—	—
Amortization of prior service cost	1	1	1	(1)	(1)	(1)
Amortization of net transition liability	16	16	16	—	—	—
Amortization of loss	10	7	8	2	1	1
Net periodic other post-retirement benefit costs	$ 76	$ 57	$ 58	$12	$ 9	$ 8

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

Reconciliation of Funded Status to Accrued Other Post-Retirement Benefit Costs

	Duke Energy U.S.		Westcoast	
	As of and for the Years Ended December 31,			
	2006	2005	2006	2005
	(in millions)			
Change in Benefit Obligation				
Accumulated post-retirement benefit obligation at prior measurement date	$ 791	$782	$117	$ 86
Service cost	10	6	4	3
Interest cost	56	45	7	6
Plan participants' contributions	25	21	—	—
Actuarial (gain) / loss	(4)	17	(34)	21
Benefits paid	(88)	(80)	(4)	(3)
Accrued RDS subsidy	4	—	—	—
Obligation assumed from acquisition	470	—	—	—
Foreign currency impact	—	—	1	4
Accumulated post-retirement benefit obligation at measurement date	$1,264	$791	$ 91	$117

	Duke Energy U.S.		Westcoast	
	As of and for the Years Ended December 31,			
	2006	2005	2006	2005
	(in millions)			
Change in Fair Value of Plan Assets				
Plan assets at prior measurement date	$ 242	$ 243	$ —	$ —
Actual return on plan assets	12	21	—	—
Benefits paid	(88)	(80)	(4)	(3)
Employer contributions	46	37	4	3
Plan participants' contributions	25	21	—	—
Plan assets at measurement date	$ 237	$ 242	$ —	$ —
Funded status	$(1,027)	$(549)	$(91)	$(117)
Employer contributions made after measurement date	17	10	1	1
Unrecognized net experience loss	—	209	—	49
Unrecognized prior service cost	—	1	—	(11)
Unrecognized transition obligation	—	111	—	—
Accrued other post-retirement benefit costs recognized	$(1,010)	$(218)	$(90)	$ (78)

Other Post-Retirement Benefit Plans—Amounts Recognized in the Consolidated Balance Sheets Consist of:

	Duke Energy U.S.		Westcoast	
	As of December 31,			
	2006	2005	2006	2005
	(in millions)			
Accrued other post-retirement liability[(a)]	$(1,010)	$(218)	$(90)	$(78)
Intangible asset	—	—	—	—
Pre-funded pension costs	—	—	—	—

Net amount recognized	$(1,010)	$(218)	$(90)	$(78)

(a) Duke Energy U.S. includes approximately $26 million and Westcoast includes approximately $4 million recognized in Other within Current Liabilities on the Consolidated Balance Sheets as of December 31, 2006.

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

As a result of the adoption of SFAS No 158, certain previously unrecognized amounts were recognized in the amounts noted above with an offset to Accumulated Other Comprehensive Income, Deferred Income Taxes and Regulatory Assets as of December 31, 2006. The table below details the components of these balances

Other Post-Retirement Benefit Plans—Amounts Recognized in Regulatory Assets and Accumulated Other Comprehensive Income Consist of:

	Duke Energy U.S.	Westcoast
	As of December 31, 2006	
	(in millions)	
Regulatory Assets	$111	$ —
Accumulated other comprehensive income		
Deferred Income tax asset	$ (66)	$ (1)
Net Transition Obligation	95	—
Prior Service Cost	(2)	(11)
Net Actuarial Loss	89	14
Net amount recognized—Accumulated other comprehensive income	$116	$ 2

Other Post Retirement Benefit Plans—Amounts in Regulatory Assets and Accumulated Other Comprehensive Income to be Recognized in Net Periodic Other Post-Retirement Benefit Costs in 2007 Consist of:

	Duke Energy U.S.
	(in millions)
Unrecognized Transition (Asset)/Liability	$ 16
Unrecognized (Gains)/Losses	8
Unrecognized Prior Service Cost	1
Net amount to be recognized	$ 25

Amounts in the above table exclude Westcoast due to the spin-off of the natural gas businesses on January 2, 2007.

For measurement purposes, plan assets were valued as of September 30 for both the Duke Energy U.S. and Westcoast plans. In May 2004, the FASB staff issued FSP No. FAS 106-2. The Modernization Act introduced a prescription drug benefit under Medicare as well as a federal subsidy to sponsors of retiree health care benefit plans. The FSP provides guidance on the accounting for the subsidy. Duke Energy adopted this FSP and retroactively applied this FSP as of the date of issuance for its U.S. plan. As a result of anticipated prescription drug subsidy, the accumulated post-retirement benefit obligation had a one time decrease of $96 million in 2004. The after-tax effect on net periodic post-retirement benefit cost was a decrease of $8 million in 2006, $7 million in 2005 and $12 million for 2004. The actuarial gain included in the change in benefit obligation of $134 million in 2004 is primarily due to the recognition of anticipated employer savings as a result of Medicare Part D. FSP No. FAS 106-2 provides guidance that the effect of the federal subsidy should be recognized as an actuarial gain. Duke Energy has recognized an approximate $5 million subsidy receivable, which is included in Receivables on the Consolidated Balance Sheets.

Assumptions Used for Other Post-Retirement Benefits Accounting

	Duke Energy U.S.			Westcoast		
Determined Benefit Obligations	2006	2005	2004	2006	2005	2004
	(percentages)					
Discount rate	5.75	5.50	6.00	5.00	5.00	6.25
Salary increase	5.00	5.00	5.00	3.50	3.25	3.25

	Duke Energy U.S.			Westcoast		
Determined Expense	2006	2005	2004	2006	2005	2004
Discount rate	5.50-6.00	6.00	6.00	5.00	6.25	6.00
Salary increase	5.00	5.00	5.00	3.25	3.25	3.25
Expected long-term rate of return on plan assets	5.53-8.50	8.50	8.50	—	—	—

Assumed tax rate[a]	35.0	35.0	35.0	—	—	—

(a) Applicable to the health care portion of funded post-retirement benefits

Notes To Consolidated Financial Statements—(Continued)

For the Duke Energy U.S. plans the discount rate used to determine the post-retirement obligation is based on a AA bond yield curve. The yield is selected based on bonds with cash flows that match the timing and amount of the expected benefit payments under the plan. For legacy Cinergy plans, the discount rate used to determine expense reflects remeasurement as of April 1, 2006 due to the merger between Duke Energy and Cinergy.

For Westcoast the discount rate used to determine the post-retirement obligation is prescribed as the yield on Canadian corporate AA bonds at the measurement date of September 30. The yield is selected based on bonds with cash flows that match the timing and amount of the expected benefit payments under the plan.

Other Post-Retirement Plan Assets—Duke Energy U.S.:

Asset Category	Target Allocation	Percentage of Plan Assets at September 30 2006	2005
U.S. equity securities	46%	46%	46%
Non-U.S. equity securities	18	19	21
Debt securities	32	32	29
Real estate	4	3	4
Total	100%	100%	100%

Duke Energy U.S. assets for both the pension and other post-retirement benefits are maintained by two Master Trusts. The investment objective of the trusts is to achieve reasonable returns on trust assets, subject to a prudent level of portfolio risk, for the purpose of enhancing the security of benefits for plan participants. The asset allocation targets were set after considering the investment objective and the risk profile with respect to the trusts. U.S. equities are held for their high expected return. Non-U.S. equities, debt securities, and real estate are held for diversification. Investments within asset classes are to be diversified to achieve broad market participation and reduce the impact of individual managers or investments. Duke Energy regularly reviews its actual asset allocation and periodically rebalances its investments to the targeted allocation when considered appropriate. The long-term rate of return of 8.5% as of September 30, 2006 for the Duke Energy U.S. assets was developed using a weighted-average calculation of expected returns based primarily on future expected returns across asset classes considering the use of active asset managers. The weighted-average returns expected by asset classes were 4.2% for U.S. equities, 1.8% for Non-U.S. equities, 2.2% for fixed income securities, and 0.3% for real estate.

Duke Energy also invests other post-retirement assets in the Duke Energy Corporation Employee Benefits Trust (VEBA I) and the Duke Energy Corporation Post-Retirement Medical Benefits Trust (VEBA II). The investment objective of the VEBA's is to achieve sufficient returns on trust assets, subject to a prudent level of portfolio risk, for the purpose of promoting the security of plan benefits for participants. The VEBA trusts are passively managed. VEBA I has a target allocation of 30% U.S. equities, 45% fixed income securities and 25% cash. VEBA II has a target allocation of 50% U.S. equities and 50% fixed income securities.

Assumed Health Care Cost Trend Rates [a]

	Duke Energy U.S.	Medical Trend Rate: Not Medicare Eligible	Medical Trend Rate: Medicare Eligible	Prescription Drug Trend Rate	Westcoast	
	2006	2005	2005	2006	2006	2005
Health care cost trend rate assumed for next year	8.50%	8.50%	11.50%	13.00%	8.0%	7.00%
Rate to which the cost trend is assumed to decline (the ultimate trend rate)	4.75%	5.50%	5.50%	4.75%	5.00%	5.00%
Year that the rate reaches the ultimate trend rate	2013	2009	2012	2022	2009	2008

(a) Health care cost trend rates for 2006 include prescription drug trend rates due to the effect of the Modernization Act.

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

Sensitivity to Changes in Assumed Health Care Cost Trend Rates Duke Energy U.S. Plans (millions)

	1-Percentage-Point Increase	1-Percentage-Point Decrease
Effect on total service and interest costs	$ 6	$ (5)
Effect on post-retirement benefit obligation	86	(75)

Sensitivity to Changes in Assumed Health Care Cost Trend Rates Westcoast Plans (millions)

	1-Percentage-Point Increase	1-Percentage-Point Decrease
Effect on total service and interest costs	$ 2	$ (1)
Effect on post-retirement benefit obligation	6	(5)

Duke Energy and Westcoast expect to make the future benefit payments, which reflect expected future service, as appropriate. Duke Energy expects to receive future subsidies under Medicare Part D. The following benefit payments and subsidies are expected to be paid (or received) over each of the next five years and thereafter.

Other Post-Retirement Plan—Expected Benefit Payments and Subsidies (in millions)

	U.S. Plan Payments	U.S. Plan Expected Subsidies	Westcoast Plans
		(in millions)	
2007	$ 77	$ 7	$ 4
2008	81	7	4
2009	84	8	4
2010	88	8	4
2011	92	9	4
2012 – 2016	491	48	23

23. Variable Interest Entities

Power Sale Special Purpose Entities (SPEs). In accordance with FIN 46, Duke Energy consolidates two SPEs that have individual power sale agreements with Central Maine Power Company (CMP) for approximately 45 megawatts (MW) of capacity, ending in 2009, and 35 MW of capacity, ending in 2016. In addition, these SPEs have individual power purchase agreements with Cinergy Capital & Trading, Inc. (Capital & Trading) to supply the power. Capital & Trading also provides various services, including certain credit support facilities. As a result of the consolidation of these two SPEs, approximately $171 million of notes receivable (which are included in Receivables on the Consolidated Balance Sheets), $160 million of non-recourse debt (which is included in Long-Term Debt on the Consolidated Balance Sheets), and miscellaneous other assets and liabilities are included on Duke Energy's Consolidated Balance Sheets. The debt was incurred by the SPEs to finance the buyout of the existing power contracts that CMP held with the former suppliers. The notes receivable is comprised of two separate notes with one counterparty, whose credit rating is BBB. The cash flows from the notes receivable are designed to repay the debt. The first note receivable, with a December 31, 2006 balance of $62 million, bears an effective interest rate of 7.81 % and matures in August 2009. The second note receivable, with a balance of $109 million as of December 31, 2006, bears an effective interest rate of 9.23 % and matures in December 2016.

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

The following table reflects the maturities of the Notes Receivable as of December 31, 2006:

Notes Receivable Maturities

	(in millions)
2007	$ 25
2008	29
2009	24
2010	8
2011	10
Thereafter	75
Total	$ 171

Subsidiary Trust Preferred Securities. In 2001, Cinergy issued approximately $316 million notional amount of 6.9 % trust preferred securities, due February 2007. The trust preferred securities were issued through a trust whose common stock was 100 % owned by Cinergy. The trust loaned the proceeds from the issuance of the securities to Cinergy in exchange for a note payable to the trust. Each Unit receives quarterly cash payments of 6.9 % per annum of the notional amount, which represents a trust preferred security dividend. The trust's ability to pay dividends on the trust preferred securities is solely dependent on its receipt of interest payments from Cinergy on the note payable. However, Cinergy has fully and unconditionally guaranteed the trust preferred securities. The trust preferred securities are not included in Duke Energy's Balance Sheets. In addition, the note payable owed to the trust, which amounts to approximately $326 million at December 31, 2006, is included in Current Maturities of Long-Term Debt on the Consolidated Balance Sheets. In February 2007, these trust preferred securities were redeemed on their scheduled maturity date and the note payable was settled.

Accounts Receivable Securitization. During 2002, Duke Energy Ohio, Duke Energy Indiana and Duke Energy Kentucky entered into an agreement to sell certain of their accounts receivable and related collections through Cinergy Receivables, a bankruptcy remote, special purpose entity. Cinergy Receivables is a wholly owned limited liability company of Cinergy. As a result of the securitization, Duke Energy Ohio, Duke Energy Indiana and Duke Energy Kentucky sell, on a revolving basis, nearly all of their retail accounts receivable and related collections. The securitization transaction was structured to meet the criteria for sale treatment under SFAS No. 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities," (SFAS No. 140) and accordingly Duke Energy does not consolidate Cinergy Receivables and the transfers of receivables are accounted for as sales.

The proceeds obtained from the sales of receivables are largely cash but do include a subordinated note from Cinergy Receivables for a portion of the purchase price (typically approximates 25 % of the total proceeds). The note, which amounts to approximately $210 million at December 31, 2006, is subordinate to senior loans that Cinergy Receivables obtains from commercial paper conduits controlled by unrelated financial institutions. Cinergy Receivables provides credit enhancement related to senior loans in the form of over-collateralization of the purchased receivables. However, the over-collateralization is calculated monthly and does not extend to the entire pool of receivables held by Cinergy Receivables at any point in time. As such, these senior loans do not have recourse to all assets of Cinergy Receivables. These loans provide the cash portion of the proceeds paid to Duke Energy Ohio, Duke Energy Indiana and Duke Energy Kentucky.

This subordinated note is a retained interest (right to receive a specified portion of cash flows from the sold assets) under SFAS No. 140 and is classified within Receivables in the accompanying Consolidated Balance Sheets at December 31, 2006. In addition, Duke Energy's investment in Cinergy Receivables constitutes a purchased beneficial interest (purchased right to receive specified cash flows, in our case residual cash flows), which is subordinate to the retained interests held by Duke Energy Ohio, Duke Energy Indiana and Duke Energy Kentucky.

The carrying values of the retained interests are determined by allocating the carrying value of the receivables between the assets sold and the interests retained based on relative fair value. The key assumptions used in estimating the fair value for 2006 were an anticipated credit loss ratio of 0.7%, a discount rate of 7.4% and a receivable turnover rate of 12.0%. Because (a) the receivables generally turnover in less than two months, (b) credit losses are reasonably predictable due to the broad customer base and lack of significant concentration, and (c) the purchased beneficial interest is subordinate to all retained interests and thus would absorb losses first, the allocated bases of the subordinated notes are not materially different than their face value. The hypothetical effect on the fair value of the retained interests assuming both a 10% and a 20% unfavorable variation in credit losses or discount rates is not material due to the short turnover of receivables and historically low credit loss history. Interest accrues to Duke Energy Ohio, Duke Energy Indiana and Duke Energy Kentucky on the retained interests using the accretable yield method, which generally approximates the stated rate on the notes since the allocated basis and the face value are nearly equivalent. Duke Energy records income from Cinergy Receivables in a similar manner. An impairment charge is recorded against the carrying value of both the retained interests and purchased beneficial interest whenever it is determined that an other-than-temporary impairment has occurred (which is unlikely unless credit losses on the receivables far exceed the anticipated level).

Duke Energy Ohio retains servicing responsibilities for its role as a collection agent on the amounts due on the sold receivables. However, Cinergy Receivables assumes the risk of collection on the purchased receivables without recourse to Duke Energy Ohio, Duke Energy Indiana and Duke Energy Kentucky in the event of a loss. While no direct recourse to Duke Energy Ohio, Duke Energy Indiana and Duke Energy Kentucky exists, these entities risk loss in the event collections are not sufficient to allow for full recovery of their retained interests. No servicing asset or liability is recorded since the servicing fee paid to Duke Energy Ohio approximates a market rate.

The following table shows the gross and net receivables sold, retained interests, purchased beneficial interest, sales, and cash flows during the period from the date of acquisition (April 1, 2006) through December 31, 2006:

	December 31, 2006 (in millions)
Receivables sold as of December 31, 2006	$ 573
Less: Retained interests	210
Net receivables sold as of December 31, 2006	$ 363
Purchased beneficial interest	$ 20
Sales from April 1, 2006 through December 31, 2006	
Receivables sold	$ 3,546
Loss recognized on sale	49
Cash flows from April 1, 2006 through December 31, 2006	
Cash proceeds from sold receivables	$ 3,465
Collection fees received	2
Return received on retained interests	23

Cash flows from the sale of receivables for the period from the date of acquisition through December 31, 2006 are reflected within Operating Activities on the Consolidated Statements of Cash Flows.

24. Other Income and Expenses, net

The components of Other Income and Expenses, net on the Consolidated Statements of Operations for the years ended December 31, 2006, 2005 and 2004 are as follows:

	For the years ended December 31,		
	2006	2005	2004
		(in millions)	
Income/(Expense)			
Interest income	$ 190	$ 75	$ 71
Foreign exchange gains (losses)	8	(9)	22
Deferred returns and AFUDC	43	17	16
Realized and unrealized mark-to-market impact on discontinued hedges	(19)	(64)	—
Income related to a distribution from an investment at Crescent	—	45	—
Other	59	41	38
Total	$ 281	$ 105	$ 147

25. Subsequent Events

The spin-off of the natural gas businesses was effective January 2, 2007. The new natural gas company, which is named Spectra Energy, principally consists of Duke Energy's Natural Gas Transmission business segment, which includes Union Gas, and also includes

Duke Energy's 50% ownership interest in DEFS. Approximately $20 billion of assets, $13 billion of liabilities (which includes approximately $8.6 billion of debt issued by Spectra Energy Capital and its consolidated subsidiaries), and $7 billion of common stockholders' equity were distributed from Duke Energy as of the date of the spin-off. Assets and liabilities of entities included in the spin-off of Spectra Energy were transferred from Duke Energy on a historical cost basis on the date of the spin-off transaction. As a result of the spin-off transaction, on January 2, 2007, in lieu of adjusting the conversion ratio of the convertible debt, Duke Energy issued approximately 2.4 million shares of Spectra Energy common stock to holders of Duke Energy's convertible senior notes due 2023, consistent with the terms of the debt agreements. The issuance of Spectra Energy shares to the convertible debt holders is expected to result in a pretax charge in the range of $20 million to $30 million in Duke Energy's 2007 consolidated statement of operations. The historical results of the natural gas businesses are expected to be treated as discontinued operations at Duke Energy in future periods beginning with the first quarter of 2007. The primary businesses remaining in Duke Energy post-spin are the U.S. Franchised Electric and Gas business segment, the Commercial Power business segment, the International Energy business segment and Duke Energy's effective 50% interest in the Crescent JV.

For information on other subsequent events, see Notes 1, 2, 3, 4, 12, 17, 18 and 23

26. Quarterly Financial Data (Unaudited)

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
	(In millions, except per share data)				
2006[a]					
Operating revenues	$3,106	$ 3,865	$ 4,143	$ 4,070	$15,184
Operating income	818	738	1,203	409	3,168
Net income	358	355	763	387	1,863
Earnings available for common stockholders	358	355	763	387	1,863
Earnings per share:					
Basic[b]	$ 0.39	$ 0.29	$ 0.61	$ 0.31	$ 1.59
Diluted[b]	$ 0.37	$ 0.28	$ 0.60	$ 0.31	$ 1.57
2005[a]					
Operating revenues	$5,218	$ 5,156	$ 2,894	$ 3,029	$16,297
Operating income	717	775	1,520	594	3,606
Net income	868	309	41	606	1,824
Earnings available for common stockholders	866	307	38	601	1,812
Earnings per share:					
Basic[b]	$ 0.91	$ 0.33	$ 0.04	$ 0.65	$ 1.94
Diluted[b]	$ 0.88	$ 0.32	$ 0.04	$ 0.63	$ 1.88

(a) Operating revenues and operating income for quarterly periods in 2006 and 2005 have changed from prior filings as a result of the classification of DEM from continuing operations to discontinued operations for all periods presented.

(b) Quarterly EPS amounts are meant to be stand-alone calculations and are not always additive to full-year amount due to rounding.

During the first quarter of 2006, Duke Energy recorded the following unusual or infrequently occurring item: an approximate $24 million pre-tax gain on the settlement of a customer's transportation contract (see Note 2).

During the second quarter of 2006, Duke Energy recorded the following unusual or infrequently occurring items: approximately $55 million pre-tax charge related to voluntary and involuntary severance as a result of the merger with Cinergy (see Note 12); an approximate $55 million pre-tax other-than-temporary impairment charge related to International Energy's investment in Campeche (see Note 12) and the issuance of approximately 313 million shares of common stock in connection with the merger with Cinergy (see Note 1).

During the third quarter of 2006, Duke Energy recorded the following unusual or infrequently occurring items: an approximate $246 million pre-tax gain on the sale of an effective 50% interest in the Crescent JV (see Note 2); and an approximate $40 million additional gain on the sale of DENA's assets to LS Power as a result of LS Power obtaining certain regulatory approvals (see Note 13).

During the fourth quarter of 2006, Duke Energy recorded the following unusual or infrequently occurring items: an approximate $65 million pre-tax contract settlement negotiation reserve (see Note 17); an approximate $100 million pre-tax charge to establish a settlement reserve related to the Citrus litigation (see Note 17); approximately $75 million of tax benefits (see Note 6); an approximate $25 million pre-tax gain on the sale of CMT (see Note 13); and an approximate $28 million pre-tax impairment charge at International Energy as a result of the pending sale of operations in Bolivia (see Note 12)

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

During the first quarter of 2005, Duke Energy recorded the following unusual or infrequently occurring items: an approximate $0.9 billion (net of minority interest of approximately $0.3 billion) pre-tax gain on sale of DEFS' wholly-owned subsidiary, Texas Eastern Products Pipeline Company, LLC (see Note 2); an approximate $100 million pre-tax gain on sale of Duke Energy's limited partner interest in TEPPCO Partners, L.P. (see Note 2); an approximate $21 million pre-tax gain on sale of DENA's partially completed Grays Harbor power plant in Washington State (see Note 2); an approximate $230 million of unrealized pre-tax losses on certain 2005 and 2006 derivative contracts hedging Field Services commodity price risk which were discontinued as cash flow hedges as a result of the anticipated deconsolidation of DEFS by Duke Energy (see Note 2); and an approximate $30 million mutual liability adjustment related to Bison which was an immaterial correction of an accounting error related to prior periods.

During the third quarter of 2005, Duke Energy recorded the following unusual or infrequently occurring items: an approximate $1.3 billion pre-tax charge for the impairment of assets and the discontinuance of hedge accounting for certain positions at DENA, as a result of the decision to exit substantially all of DENA's remaining assets and contracts outside the Midwestern United States and certain contractual positions related to the Midwestern Assets (see Note 13); an approximate $575 million pre-tax gain associated with the transfer of 19.7% of Duke Energy's interest in DEFS to ConocoPhillips, Duke Energy's co-equity owner in DEFS, which reduced Duke Energy's ownership interest in DEFS from 69.7% to 50% (see Note 2); an approximate $105 million of unrealized and realized pre-tax losses on certain 2005 and 2006 derivative contracts hedging Field Services commodity price risk which were discontinued as cash flow hedges as a result of the deconsolidation of DEFS by Duke Energy (see Note 2); and approximately $90 million of gains at Crescent due primarily to income related to a distribution from an interest in a portfolio of office buildings and a large land sale.

During the fourth quarter of 2005, Duke Energy recorded the following unusual or infrequently occurring items: pre-tax gain of approximately $300 million, which reverses a portion of the third quarter DENA impairment, attributable to the planned asset sales to LS Power; and pre-tax losses of approximately $475 million for portfolio exit costs including severance, retention and other transaction costs at DENA (see Note 13).

DUKE ENERGY CORPORATION

SCHEDULE II—VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

	Balance at Beginning of Period	Additions [c]: Charged to Expense	Additions [c]: Charged to Other Accounts	Deductions[a]	Balance at End of Period
			(In millions)		
December 31, 2006:					
Injuries and damages	$1,216	$ 7	$ 10	$ 49	$ 1,184
Allowance for doubtful accounts	127	38	21	92	94
Other[b]	896	468	287	532	1,119
	$2,239	$513	$ 318	$ 673	$ 2,397
December 31, 2005:					
Injuries and damages	$1,269	$ 4	$ —	$ 57	$ 1,216
Allowance for doubtful accounts	135	33	10	51	127
Other[b]	905	336	77	422	896
	$2,309	$373	$ 87	$ 530	$ 2,239
December 31, 2004:					
Injuries and damages	$1,319	$ 8	$ 2	$ 60	$ 1,269
Allowance for doubtful accounts	280	77	4	226	135
Other[b]	1,162	245	96	598	905
	$2,761	$330	$ 102	$ 884	$ 2,309

(a) Principally cash payments and reserve reversals

(b) Principally insurance related reserves at Bison, uncertain tax provisions, litigation and other reserves, included in Other Current Liabilities, or Deferred Credits and Other *Liabilities on the Consolidated* Balance Sheets.

(c) 2006 balances include balances and activity related to Duke Energy's merger with Cinergy in April 2006.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure.

None.

Item 9A. Controls and Procedures.

Disclosure Controls and Procedures

Disclosure controls and procedures are controls and other procedures that are designed to ensure that information required to be disclosed by Duke Energy in the reports it files or submits under the Securities Exchange Act of 1934 (Exchange Act) is recorded, processed, summarized, and reported, within the time periods specified by the Securities and Exchange Commission's (SEC) rules and forms.

Disclosure controls and procedures include, without limitation, controls and procedures designed to provide reasonable assurance that information required to be disclosed by Duke Energy in the reports it files or submits under the Exchange Act is accumulated and communicated to management, including the Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Under the supervision and with the participation of management, including the Chief Executive Officer and Chief Financial Officer, Duke Energy has evaluated the effectiveness of its disclosure controls and procedures (as such term is defined in Rule 13a-15(e) and 15d-15(e) under the Exchange Act) as of December 31, 2006, and, based upon this evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that these controls and procedures are effective in providing reasonable assurance that information requiring disclosure is recorded, processed, summarized, and reported within the timeframe specified by the SEC's rules and forms.

Changes in Internal Control over Financial Reporting

Under the supervision and with the participation of management, including the Chief Executive Officer and Chief Financial Officer, Duke Energy has evaluated changes in internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) that occurred during the fiscal quarter ended December 31, 2006 and, other than the Duke Energy and Cinergy merger discussed below, found no change that has materially affected, or is reasonably likely to materially affect, internal control over financial reporting.

On April 3, 2006, the previously announced merger between Duke Energy and Cinergy was consummated. Duke Energy is in process of integrating Cinergy's operations and has included Cinergy's activity in its evaluation of internal control over financial reporting pursuant to Section 404 of the Sarbanes-Oxley Act of 2002. See Notes 1, 2 and 3 to the Consolidated Financial Statements for additional information relating to the merger.

Management's Annual Report On Internal Control Over Financial Reporting

Duke Energy's management is responsible for establishing and maintaining an adequate system of internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f) and 15d-15(f). Our internal control system was designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes, in accordance with generally accepted accounting principles. Because of inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with policies and procedures may deteriorate.

Duke Energy's management, including our Chief Executive Officer and Chief Financial Officer, has conducted an evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2006 based on the framework in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on that evaluation, management concluded that our internal control over financial reporting was effective as of December 31, 2006.

Deloitte & Touche LLP, our independent registered public accounting firm, has issued an attestation report on management's assessment of our internal control over financial reporting. That report immediately follows.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of Duke Energy Corporation

We have audited management's assessment, included in the accompanying Management's Annual Report on Internal Control Over Financial Reporting, that Duke Energy Corporation and subsidiaries (the "Company") maintained effective internal control over financial reporting as of December 31, 2006, based on criteria established in *Internal Control--Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management's assessment that the Company maintained effective internal control over financial reporting as of December 31, 2006, is fairly stated, in all material respects, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and financial statement schedule as of and for the year ended December 31, 2006 of the Company and our report dated March 1, 2007 expressed an unqualified opinion on those financial statements and financial statement schedule and included explanatory paragraphs regarding the Company's adoption of a new accounting standard and the January 2, 2007 spin-off of the Company's natural gas businesses.

/s/ DELOITTE & TOUCHE LLP

Charlotte, North Carolina

March 1, 2007

Item 10. Directors, Executive Officers and Corporate Governance.

Reference to "Executive Officers of Duke Energy" is included in "Item 1. Business" of this report. Information in response to this item is incorporated by reference to Duke Energy's Proxy Statement relating to Duke Energy's 2007 annual meeting of shareholders.

Item 11. Executive Compensation.

Information in response to this item is incorporated by reference to Duke Energy's Proxy Statement relating to Duke Energy's 2007 annual meeting of shareholders.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.

Information in response to this item is incorporated by reference to Duke Energy's Proxy Statement relating to Duke Energy's 2007 annual meeting of shareholders.

This table shows information about securities to be issued upon exercise of outstanding options, warrants and rights under Duke Energy's equity compensation plans, along with the weighted-average exercise price of the outstanding options, warrants and rights and the number of securities remaining available for future issuance under the plans.

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights[1] (a)	Weighted-average exercise price of outstanding options, warrants and rights[1] (b)	Number of securities remaining available under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders	19,427,112[2]	$ 30.29	59,978,000[3]
Equity compensation plans not approved by security holders	1,877,646[4]	29.14	None
Total	21,304,758	$ 30.19	59,978,000

1 Duke Energy has not granted any warrants or rights under any equity compensation plans. Amounts do not include 5,409,873 outstanding options with a weighted average exercise price of $24.27 assumed in connection with various mergers and acquisitions.

2 Does not include 6,222,165 shares of Duke Energy Common Stock to be issued upon vesting of phantom stock and performance share awards outstanding as of December 31, 2006.

3 Includes 14,978,000 shares remaining available for issuance for awards of restricted stock, performance shares or phantom stock under the Duke Energy Corporation 2006 Long-Term Incentive Plan.

4 Does not include 516,435 shares of Duke Energy Common Stock to be issued upon vesting of phantom stock and performance share awards outstanding as of December 31, 2006.

Item 13. Certain Relationships and Related Transactions, and Director Independence

Information in response to this item is incorporated by reference to Duke Energy's Proxy Statement relating to Duke Energy's 2007 annual meeting of shareholders.

Item 14. Principal Accounting Fees and Services.

Information in response to this item is incorporated by reference to Duke Energy's Proxy Statement relating to Duke Energy's 2007 annual meeting of shareholders.

Item 15. Exhibits, Financial Statement Schedules.

(a) Consolidated Financial Statements, Supplemental Financial Data and Supplemental Schedules included in Part II of this annual report are as follows:

Duke Energy Corporation:

Consolidated Financial Statements

Consolidated Statements of Operations for the Years Ended December 31, 2006, 2005 and 2004

Consolidated Balance Sheets as of December 31, 2006 and 2005

Consolidated Statements of Cash Flows for the Years Ended December 31, 2006, 2005 and 2004

Consolidated Statements of Common Stockholders' Equity and Comprehensive Income for the Years ended December 31, 2006, 2005 and 2004

Notes to the Consolidated Financial Statements

Quarterly Financial Data, as revised *(unaudited, included in Note 26* to the Consolidated Financial Statements)

Consolidated Financial Statement Schedule II—Valuation and Qualifying Accounts and Reserves for the Years Ended December 31, 2006, 2005 and 2004

Report of Independent Registered Public Accounting Firm

Seperate Financial Statements of Subsidiaries not Consolidated Pursuant to Rule 3-09 of Regulation S-X:

TEPPCO Partners, L.P :

Report of Independent Registered Public Accounting Firm

Consolidated Balance Sheets as of December 31, 2005 and 2004

Consolidated Statements of Income for the Years Ended December 31, 2005, 2004 and 2003

Consolidated Statements of Cash Flows for the Years Ended December 31, 2005, 2004 and 2003

Consolidated Statements of Partners' Capital for the Years Ended December 31, 2005, 2004 and 2003

Consolidated Statements of Comprehensive Income for the Years Ended December 31, 2005, 2004 and 2003

Notes to Consolidated Financial Statements

All other schedules are omitted because they are not required, or because the required information is included in the Consolidated Financial Statements or Notes

The consolidated financial statements of DCP Midstream, LLC (formerly Duke Energy Field Services, LLC), Duke Energy's 50/50 joint venture with ConocoPhillips, required to be included in this report pursuant to Rule 3-09 of Regulation S-X are to be filed by amendment no later than March 31, 2007

(c) Exhibits—See Exhibit Index immediately following the signature page

Table of Contents

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

Date: March 1, 2007

DUKE ENERGY CORPORATION

(Registrant)

By: /S/ JAMES E. ROGERS

James E. Rogers

Chairman, President and

Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the date indicated.

(i) James E. Rogers*

Chairman, President and Chief Executive Officer (Principal Executive Officer and Director)

(ii) /s/ David L. Hauser

Group Executive and Chief Financial Officer (Principal Financial Officer)

(iii) Steven K. Young*

Senior Vice President and Controller (Principal Accounting Officer)

(iv) William Barnet, III*

Director

G. Alex Bernhardt, Sr.*

Director

Michael G. Browning*

Director

Phillip R. Cox*

Director

Ann Maynard Gray*

Director

James H. Hance, Jr.*

Director

James T. Rhodes*

Director

Mary L. Schapiro*

Director

Dudley S. Taft*

Director

Date: March 1, 2007

David L. Hauser, by signing his name hereto, does hereby sign this document on behalf of the registrant and on behalf of each of the above-named persons previously indicated by asterisk pursuant to a power of attorney duly executed by the registrant and such persons, filed with the Securities and Exchange Commission as an exhibit hereto.

By: /s/ DAVID L. HAUSER

Attorney-In-Fact

Table of Contents

CONSOLIDATED FINANCIAL STATEMENTS OF

TEPPCO PARTNERS, L.P.

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Table of Contents

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Partners of TEPPCO Partners, L.P.:

We have audited the accompanying consolidated balance sheets of TEPPCO Partners, L.P. and subsidiaries as of December 31, 2005 and 2004, and the related consolidated statements of income, partners' capital and comprehensive income, and cash flows for each of the years in the three-year period ended December 31, 2005 These consolidated financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of TEPPCO Partners, L.P. and subsidiaries as of December 31, 2005 and 2004, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2005, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 20 to the consolidated financial statements, the Partnership has restated its consolidated balance sheet as of December 31, 2004, and the related consolidated statements of income, partners' capital and comprehensive income, and cash flows for the years ended December 31, 2004 and 2003.

KPMG LLP

Houston, Texas

February 28, 2006, except for the effects of discontinued operations,

as discussed in Note 5, which is as of June 1, 2006

Table of Contents

TEPPCO PARTNERS, L.P.

Consolidated Balance Sheets

(in thousands)

	December 31, 2005	December 31, 2004 (as restated)
ASSETS		
Current assets:		
Cash and cash equivalents	$ 119	$ 16,422
Accounts receivable, trade (net of allowance for doubtful accounts of $250 and $112)	803,373	553,628
Accounts receivable, related parties	5,207	11,845
Inventories	29,069	19,521
Other	61,361	42,138
Total current assets	899,129	643,554
Property, plant and equipment, at cost (net of accumulated depreciation and amortization of $474,332 and $407,670)	1,960,068	1,703,702
Equity investments	359,656	363,307
Intangible assets	376,908	407,358
Goodwill	16,944	16,944
Other assets	67,833	51,419
Total assets	$3,680,538	$ 3,186,284
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Accounts payable and accrued liabilities	$ 800,033	$ 564,464
Accounts payable, related parties	11,836	24,654
Accrued interest	32,840	32,292
Other accrued taxes	16,532	13,309
Other	75,970	46,593
Total current liabilities	937,211	681,312
Senior Notes	1,119,121	1,127,226
Other long-term debt	405,900	353,000
Other liabilities and deferred credits	16,936	13,643
Commitments and contingencies		
Partners' capital:		
Accumulated other comprehensive income	11	—
General partner's interest	(61,487)	(35,881)
Limited partners' interests	1,262,846	1,046,984
Total partners' capital	1,201,370	1,011,103
Total liabilities and partners' capital	$3,680,538	$ 3,186,284

See accompanying Notes to Consolidated Financial Statements.

TEPPCO PARTNERS, L.P.

Consolidated Statements of Income

(in thousands, except per Unit amounts)

	2005	2004 (as restated)	2003 (as restated)
	Years Ended December 31,		
Operating revenues:			
Sales of petroleum products	$8,061,808	$ 5,426,832	$ 3,766,651
Transportation—Refined products	144,552	148,166	138,926
Transportation—LPGs	96,297	87,050	91,787
Transportation—Crude oil	37,614	37,177	29,057
Transportation—NGLs	43,915	41,204	39,837
Gathering—Natural gas	152,797	140,122	135,144
Other	68,051	67,539	54,430
Total operating revenues	8,605,034	5,948,090	4,255,832
Costs and expenses:			
Purchases of petroleum products	7,986,438	5,367,027	3,711,207
Operating, general and administrative	218,920	219,909	198,478
Operating fuel and power	48,972	48,139	41,362
Depreciation and amortization	110,729	112,284	100,728
Taxes—other than income taxes	20,610	17,340	15,597
Gains on sales of assets	(668)	(1,053)	(3,948)
Total costs and expenses	8,385,001	5,763,646	4,063,424
Operating income	220,033	184,444	192,408
Interest expense—net	(81,861)	(72,053)	(84,250)
Equity earnings	20,094	22,148	12,874
Other income—net	1,135	1,320	748
Income from continuing operations	159,401	135,859	121,780
Discontinued operations	3,150	2,689	—
Net income	$ 162,551	$ 138,548	$ 121,780
Net Income Allocation:			
Limited Partner Unitholders income from continuing operations	$ 112,744	$ 96,667	$ 86,357
Limited Partner Unitholders income from discontinued *operations*	2,228	1,913	—
Total Limited Partner Unitholders net income allocation	114,972	98,580	86,357
Class B Unitholder net income allocation	—	—	1,754
General Partner income from continuing operations	46,657	39,192	33,669
General Partner income from discontinued operations	922	776	—
Total General Partner net income allocation	47,579	39,968	33,669
Total net income allocated	$ 162,551	$ 138,548	$ 121,780
Basic and diluted net income per Limited Partner and Class B Unit:			
Continuing *operations*	$ 1.67	$ 1.53	$ 1.47
Discontinued operations	0.04	0.03	—
Basic and diluted net income per Limited Partner and Class B Unit	$ 1.71	$ 1.56	$ 1.47
Weighted average Limited Partner and Class B Units outstanding	67,397	62,999	59,765

See accompanying Notes to Consolidated Financial Statements.

TEPPCO PARTNERS, L.P.

Consolidated Statements of Cash Flows

(in thousands)

	Years Ended December 31,		
	2005	2004	2003
		(as restated)	(as restated)
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 162,551	$ 138,548	$ 121,780
Adjustments to reconcile net income to cash provided by continuing operating activities:			
Income from discontinued operations	(3,150)	(2,689)	—
Depreciation and amortization	110,729	112,284	100,728
Earnings in equity investments, net of distributions	16,991	25,065	15,129
Gains on sales of assets	(668)	(1,053)	(3,948)
Non-cash portion of interest expense	1,624	(391)	4,793
Increase in accounts receivable	(249,745)	(181,690)	(100,085)
Decrease (increase) in accounts receivable, related parties	6,638	(14,693)	8,788
Increase in inventories	(970)	(3,433)	(956)
Increase in other current assets	(19,088)	(9,926)	(953)
Increase in accounts payable and accrued expenses	254,251	186,942	95,540
Increase (decrease) in accounts payable, related parties	(12,817)	4,360	7,381
Other	(15,623)	10,572	(5,773)
Net cash provided by continuing operating activities	250,723	263,896	242,424
Net cash provided by discontinued operations	3,782	3,271	—
Net cash provided by operating activities	254,505	267,167	242,424
CASH FLOWS FROM CONTINUING INVESTING ACTIVITIES:			
Proceeds from sales of assets	510	1,226	8,531
Proceeds from cash investments	—	—	750
Purchase of assets	(112,231)	(3,421)	(27,469)
Investment in Mont Belvieu Storage Partners, L.P.	(4,233)	(21,358)	(2,533)
Investment in Centennial Pipeline LLC	—	(1,500)	(4,000)
Purchase of additional interest in Centennial Pipeline LLC	—	—	(20,000)
Cash paid for linefill on assets owned	(14,408)	(957)	(3,070)
Capital expenditures	(220,553)	(156,749)	(126,707)
Net cash used in continuing investing activities	(350,915)	(182,759)	(174,498)
Net cash used in discontinued investing activities	—	(7,398)	(13,810)
Net cash used in investing activities	(350,915)	(190,157)	(188,308)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from revolving credit facility	657,757	324,200	382,000
Issuance of Limited Partner Units, net	278,806	—	287,506
Issuance of Senior Notes	—	—	198,570
Repayments on revolving credit facility	(604,857)	(181,200)	(604,000)
Repurchase and retirement of Class B Units	—	—	(113,814)
Debt issuance costs	(498)	—	(3,381)
General Partner's contributions	—	—	2
Distributions paid	(251,101)	(233,057)	(202,498)
Net cash provided by (used in) financing activities	80,107	(90,057)	(55,615)
Net decrease in cash and cash equivalents	(16,303)	(13,047)	(1,499)
Cash and cash equivalents at beginning of period	16,422	29,469	30,968
Cash and cash equivalents at end of period	$ 119	$ 16,422	$ 29,469
Non-cash investing activities:			
Net assets transferred to Mont Belvieu Storage Partners, L.P.	$ 1,429	$ —	$ 61,042
Supplemental disclosure of cash flows:			
Cash paid for interest (net of amounts capitalized)	$ 82,315	$ 77,510	$ 79,930

See accompanying Notes to Consolidated Financial Statements.

TEPPCO PARTNERS, L.P.

Consolidated Statements of Partners' Capital

(in thousands, except Unit amounts)

	Outstanding Limited Partner Units	General Partner's Interest	Limited Partners' Interests	Accumulated Other Comprehensive (Loss) Income	Total
Partners' capital at December 31, 2002 (as restated)	53,809,597	$ 12,104	$ 897,400	$ (20,055)	$ 889,449
Issuance of Limited Partner Units, net	9,101,650	—	285,461	—	285,461
Retirement of Class B units	—	—	(11,175)	—	(11,175)
Net income on cash flow hedge	—	—	—	16,164	16,164
Reclassification due to discontinued portion of cash flow hedge	—	—	—	989	989
2003 net income allocation	—	33,669	86,357	—	120,026
2003 cash distributions	—	(54,725)	(145,427)	—	(200,152)
Issuance of Limited Partner Units upon exercise of options	87,307	2	2,045	—	2,047
Partners' capital at December 31, 2003 (as restated)	62,998,554	(8,950)	1,114,661	(2,902)	1,102,809
Adjustments to issuance of Limited Partner Units, net	—	—	(99)	—	(99)
Net income on cash flow hedge	—	—	—	2,902	2,902
2004 net income allocation	—	39,968	98,580	—	138,548
2004 cash distributions	—	(66,899)	(166,158)	—	(233,057)
Partners' capital at December 31, 2004 (as restated)	62,998,554	(35,881)	1,046,984	—	1,011,103
Issuance of Limited Partner Units, net	6,965,000	—	278,806	—	278,806
Changes in fair values of crude oil hedges	—	—	—	11	11
2005 net income allocation	—	47,579	114,972	—	162,551
2005 cash distributions	—	(73,185)	(177,916)	—	(251,101)
Partners' capital at December 31, 2005	69,963,554	$ (61,487)	$ 1,262,846	$ 11	$ 1,201,370

See accompanying Notes to Consolidated Financial Statements.

TEPPCO PARTNERS, L.P

Consolidated Statements of Comprehensive Income

(in thousands)

	Years Ended December 31,		
	2005	2004	2003
		(as restated)	(as restated)
Net income	$162,551	$ 138,548	$ 121,780
Net income on cash flow hedges	11	—	16,164
Comprehensive income	$162,562	$ 138,548	$ 137,944

See accompanying Notes to Consolidated Financial Statements.

Notes To Consolidated Financial Statements

Note 1. Partnership Organization

TEPPCO Partners, L.P. (the "Partnership"), a Delaware limited partnership, is a master limited partnership formed in March 1990. We operate through TE Products Pipeline Company, Limited Partnership ("TE Products"), TCTM, L.P. ("TCTM") and TEPPCO Midstream Companies, L.P. ("TEPPCO Midstream"). Collectively, TE Products, TCTM and TEPPCO Midstream are referred to as the "Operating Partnerships." Texas Eastern Products Pipeline Company, LLC (the "Company" or "General Partner"), a Delaware limited liability company, serves as our general partner and owns a 2% general partner interest in us.

On July 26, 2001, the Company restructured its general partner ownership of the Operating Partnerships to cause them to be indirectly wholly owned by us. TEPPCO GP, Inc. ("TEPPCO GP"), our subsidiary, succeeded the Company as general partner of the Operating Partnerships. All remaining partner interests in the Operating Partnerships not already owned by us were transferred to us. In exchange for this contribution, the Company's interest as our general partner was increased to 2%. The increased percentage is the economic equivalent of the aggregate interest that the Company had prior to the restructuring through its combined interests in us and the Operating Partnerships. As a result, we hold a 99.999% limited partner interest in the Operating Partnerships and TEPPCO GP holds a 0.001% general partner interest. This reorganization was undertaken to simplify required financial reporting by the Operating Partnerships when the Operating Partnerships issue guarantees of our debt.

Through February 23, 2005, the General Partner was an indirect wholly owned subsidiary of Duke Energy Field Services, LLC ("DEFS"), a joint venture between Duke Energy Corporation ("Duke Energy") and ConocoPhillips. Duke Energy held an interest of approximately 70% in DEFS, and ConocoPhillips held the remaining interest of approximately 30%. On February 24, 2005, the General Partner was acquired by DFI GP Holdings L.P. (formerly Enterprise GP Holdings L.P.) ("DFI"), an affiliate of EPCO, Inc. ("EPCO"), a privately held company controlled by Dan L. Duncan, for approximately $1.1 billion. As a result of the transaction, DFI owns and controls the 2% general partner interest in us and has the right to receive the incentive distribution rights associated with the general partner interest. In conjunction with an amended and restated *administrative services agreement*, EPCO performs all management, administrative and operating functions required for us, and we reimburse EPCO for all direct and indirect expenses that have been incurred in managing us. As a result of the sale of our General Partner, DEFS and Duke Energy continued to provide some administrative services for us for a period of up to one year after the sale, at which time, we assumed these services. In connection with us assuming the operations of certain of the TEPPCO Midstream assets from DEFS, certain DEFS employees became employees of EPCO effective June 1, 2005.

At formation in 1990, we completed an initial public offering of 26,500,000 units representing Limited Partner Interests ("Limited Partner Units") at $10.00 per Limited Partner Unit. In connection with our formation, the Company received 2,500,000 Deferred Participation Interests ("DPIs"). Effective April 1, 1994, the DPIs were converted to Limited Partner Units, but they have not been listed for trading on the New York Stock Exchange. These Limited Partner Units were assigned to Duke Energy when ownership of the Company was transferred from Duke Energy to DEFS in 2000. On February 24, 2005, DFI entered into an LP Unit Purchase and Sale Agreement with Duke Energy and purchased these 2,500,000 Limited Partner Units for $104.0 million. As of December 31, 2005, none of these Limited Partner Units had been sold by DFI

At December 31, 2005, 2004 and 2003, we had outstanding 69,963,554, 62,998,554 and 62,998,554 Limited Partner Units, respectively. At December 31, 2002, we had outstanding 3,916,547 Class B Limited Partner Units ("Class B Units"), which were issued to Duke Energy Transport and Trading Company, LLC ("DETTCO") in connection with an acquisition of assets initially acquired in 1998. On April 2, 2003, we repurchased and retired all of the 3,916,547 previously outstanding Class B Units with proceeds from the issuance of additional Limited Partner Units (see Note 11). Collectively, the Limited Partner Units and Class B Units are referred to as "Units".

As used in this Report, "we," "us," "our," the "Partnership" and "TEPPCO" mean TEPPCO Partners, L.P. and, where the context requires, include our subsidiaries

We restated our consolidated financial statements and related financial information for the years ended December 31, 2004 and 2003, for an accounting correction. In addition, the restatement adjustment impacted quarterly periods with the fiscal years ended December 31, 2005, 2004 and 2003. See Note 20 for a discussion of the restatement adjustment and the impact on previously issued financial statements.

Note 2. Summary of Significant Accounting Policies

We adhere to the following significant accounting policies in the preparation of our consolidated financial statements.

Basis of Presentation and Principles of Consolidation. Throughout the consolidated financial statements and accompanying notes, all referenced amounts related to prior periods reflect the balances and amounts on a restated basis. The financial statements include our accounts on a consolidated basis. We have eliminated all significant intercompany items in consolidation. We have reclassified certain amounts from prior periods to conform to the current presentation. Our results for the years ended December 31, 2005 and 2004 reflect the operations and activities of Jonah Gas Gathering Company's Pioneer plant as discontinued operations.

Use of Estimates. The preparation of financial statements in conformity with generally accepted accounting principles in the United States requires our management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting periods. Although we believe these estimates are reasonable, actual results could differ from those estimates.

Business Segments. We operate and report in three business segments: transportation and storage of refined products, liquefied petroleum gases ("LPGs") and petrochemicals ("Downstream Segment"); gathering, transportation, marketing and storage of crude oil and distribution of lubrication oils and specialty chemicals ("Upstream Segment"); and gathering of natural gas, fractionation of natural gas liquids ("NGLs") and transportation of NGLs ("Midstream Segment"). Our reportable segments offer different products and services and are managed separately because each requires different business strategies.

Our interstate transportation operations, including rates charged to customers, are subject to regulations prescribed by the Federal Energy Regulatory Commission ("FERC"). We refer to refined products, LPGs, petrochemicals, crude oil, NGLs and natural gas in this Report, collectively, as "petroleum products" or "products."

Revenue Recognition. Our Downstream Segment revenues are earned from transportation and storage of refined products and LPGs, intrastate transportation of petrochemicals, sale of product inventory and other ancillary services. Transportation revenues are recognized as products are delivered to customers. Storage revenues are recognized upon receipt of products into storage and upon performance of storage services. Terminaling revenues are recognized as products are out-loaded. Revenues from the sale of product inventory are recognized when the products are sold.

Our Upstream Segment revenues are earned from gathering, transportation, marketing and storage of crude oil, and distribution of lubrication oils and specialty chemicals principally in Oklahoma, Texas, New Mexico and the Rocky Mountain region. Revenues are also generated from trade documentation and pumpover services, primarily at Cushing, Oklahoma, and Midland, Texas. Revenues are accrued at the time title to the product sold transfers to the purchaser, which typically occurs upon receipt of the product by the purchaser, and purchases are accrued at the time title to the product purchased transfers to our crude oil marketing company, TEPPCO Crude Oil, L.P. ("TCO"), which typically occurs upon our receipt of the product. Revenues related to trade documentation and pumpover fees are recognized as services are completed.

Except for crude oil purchased from time to time as inventory, our policy is to purchase only crude oil for which we have a market to sell and to structure sales contracts so that crude oil price fluctuations do not materially affect the margin received. As we purchase crude oil, we establish a margin by selling crude oil for physical delivery to third party users or by entering into a future delivery obligation. Through these transactions, we seek to maintain a position that is balanced between crude oil purchases and sales and future delivery obligations. However, certain basis risks (the risk that price relationships between delivery points, classes of products or delivery periods will change) cannot be completely hedged.

Our Midstream Segment revenues are earned from the gathering of natural gas, transportation of NGLs and fractionation of NGLs. Gathering revenues are recognized as natural gas is received from the customer. Transportation revenues are recognized as NGLs are delivered to customers. Revenues are also earned from the sale of condensate liquid extracted from the natural gas stream to an Upstream Segment marketing affiliate. Fractionation revenues are recognized ratably over the contract year as products are delivered. We generally do not take title to the natural gas gathered, NGLs transported or NGLs fractionated, with the exception of inventory imbalances discussed in "Natural Gas Imbalances." Therefore, the results of our Midstream Segment are not directly affected by changes in the prices of natural gas or NGLs.

Cash and Cash Equivalents. Cash equivalents are defined as all highly marketable securities with maturities of three months or less when purchased. The carrying value of cash and cash equivalents approximate fair value because of the short term nature of these investments.

Allowance for Doubtful Accounts. We establish provisions for losses on accounts receivable if we determine that we will not collect all or part of the outstanding balance. Collectibility is reviewed regularly and an allowance is established or adjusted, as necessary, using the specific identification method. The following table presents the activity of our allowance for doubtful accounts for the years ended December 31, 2005, 2004 and 2003 (in thousands):

	Years Ended December 31,		
	2005	2004	2003
Balance at beginning of period	$ 112	$ 4,700	$ 4,608
Charges to expense	829	536	793
Deductions and other	(691)	(5,124)	(701)
Balance at end of period	$ 250	$ 112	$ 4,700

Inventories. Inventories consist primarily of petroleum products and crude oil, which are valued at the lower of cost (weighted average cost method) or market. Our Downstream Segment acquires and disposes of various products under exchange agreements. Receivables and payables arising from these transactions are usually satisfied with products rather than cash. The net balances of exchange receivables and payables are valued at weighted average cost and included in inventories. Inventories of materials and supplies, used for ongoing replacements and expansions, are carried at the lower of fair value or cost.

Property, Plant and Equipment. We record property, plant and equipment at its acquisition cost. Additions to property, plant and equipment, including major replacements or betterments, are recorded at cost. We charge replacements and renewals of minor items of property that do not materially increase values or extend useful lives to maintenance expense. Depreciation expense is computed on the straight-line method using rates based upon expected useful lives of various classes of assets (ranging from 2% to 20% per annum).

We evaluate impairment of long-lived assets in accordance with Statement of Financial Accounting Standards ("SFAS") No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets. Long-lived assets are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Recoverability of the carrying amount of assets to be held and used is measured by a comparison of the carrying amount of the asset to estimated future net cash flows expected to be generated by the asset. If such assets are considered to be impaired, the impairment to be recognized is measured by the amount by which the carrying amount of the assets exceeds the estimated fair value of the assets. Assets to be disposed of are reported at the lower of the carrying amount or estimated fair value less costs to sell.

Asset Retirement Obligations. In June 2001, the Financial Accounting Standards Board ("FASB") issued SFAS No. 143, Accounting for Asset Retirement Obligations. SFAS 143 requires us to record the fair value of an asset retirement obligation as a liability in the period in which we incur a legal obligation for the retirement of tangible long-lived assets. A corresponding asset is also recorded and depreciated over the life of the asset. After the initial measurement of the asset retirement obligation, the liability will be adjusted at the end of each reporting period to reflect changes in the estimated future cash flows underlying the obligation. Determination of any amounts recognized upon adoption is based upon numerous estimates and assumptions, including future retirement costs, future inflation rates and the credit-adjusted risk-free interest rates.

The Downstream Segment assets consist primarily of an interstate trunk pipeline system and a series of storage facilities that originate along the upper Texas Gulf Coast and extend through the Midwest and northeastern United States. We transport refined products, LPGs and petrochemicals through the pipeline system. These products are primarily received in the south end of the system and stored and/or transported to various points along the system per customer nominations. The Upstream Segment's operations include purchasing crude oil from producers at the wellhead and providing delivery, storage and other services to its customers. The properties in the Upstream Segment consist of interstate trunk pipelines, pump stations, trucking facilities, storage tanks and various gathering systems primarily in Texas and Oklahoma. The Midstream Segment gathers natural gas from wells owned by producers and delivers natural gas and NGLs on its pipeline systems, primarily in Texas, Wyoming, New Mexico and Colorado. The Midstream Segment also owns and operates two NGL fractionator facilities in Colorado.

We have completed our assessment of SFAS 143, and we have determined that we are obligated by contractual or regulatory requirements to remove certain facilities or perform other remediation upon retirement of our assets. However, we are not able to reasonably determine the fair value of the asset retirement obligations for our trunk, interstate and gathering pipelines and our surface facilities, since future dismantlement and removal dates are indeterminate.

In order to determine a removal date for our gathering lines and related surface assets, reserve information regarding the production life of the specific field is required. As a transporter and gatherer of crude oil and natural gas, we are not a producer of the field reserves, and we therefore do not have access to adequate forecasts that predict the timing of expected production for existing reserves on those fields in which we gather crude oil and natural gas. In the absence of such information, we are not able to make a reasonable estimate of when future dismantlement and removal dates of our gathering assets will occur. With regard to our trunk and interstate pipelines and their related surface assets, it is impossible to predict when demand for transportation of the related products will cease. Our right-of-way agreements allow us to maintain the right-of-way rather than remove the pipe. In addition, we can evaluate our trunk pipelines for alternative uses, which can be and have been found.

We will record such asset retirement obligations in the period in which more information becomes available for us to reasonably estimate the settlement dates of the retirement obligations. The adoption of SFAS 143 did not have an effect on our financial position, results of operations or cash flows.

Capitalization of Interest. We capitalize interest on borrowed funds related to capital projects only for periods that activities are in progress to bring these projects to their intended use. The weighted average rate used to capitalize interest on borrowed funds was 5.73%, 5.74% and 6.50% for the years ended December 31, 2005, 2004 and 2003, respectively. During the years ended December 31, 2005, 2004 and 2003, the amount of interest capitalized was $6.8 million, $4.2 million and $5.3 million, respectively.

Intangible Assets. Intangible assets on the consolidated balance sheets consist primarily of gathering contracts assumed in the acquisition of Jonah Gas Gathering System ("Jonah") on September 30, 2001, and the acquisition of Val Verde Gathering System ("Val Verde") on June 30, 2002, a fractionation agreement and other intangible assets (see Note 3). Included in equity investments on the consolidated balance sheets are excess investments in Centennial Pipeline LLC ("Centennial") and Seaway Crude Pipeline Company ("Seaway").

In connection with the acquisitions of Jonah and Val Verde, we assumed contracts that dedicate future production from natural gas wells in the Green River Basin in Wyoming, and we assumed fixed-term contracts with customers that gather coal bed methane ("CBM") from the San Juan Basin in New Mexico and Colorado, respectively. The value assigned to these intangible assets relates to contracts with customers that are for either a fixed term or which dedicate total future lease production to the gathering system. These intangible assets are amortized on a unit-of-production basis, based upon the actual throughput of the system over the expected total throughput for the lives of the contracts. Revisions to the unit-of-production estimates may occur as additional production information is made available to us (see Note 3).

In connection with the purchase of the fractionation facilities in 1998, we entered into a fractionation agreement with DEFS. The fractionation agreement is being amortized on a straight-line basis over a period of 20 years, which is the term of the agreement with DEFS.

In connection with the acquisition of crude supply and transportation assets in November 2003, we acquired intangible customer contracts for $8.7 million, which are amortized on a unit-of-production basis (see Note 5).

In connection with the formation of Centennial, we recorded excess investment, the majority of which is amortized on a unit-of-production basis over a period of 10 years. In connection with the acquisition of our interest in Seaway, we recorded excess investment, which is amortized on a straight-line basis over a period of 39 years (see Note 3).

Goodwill. Goodwill represents the excess of purchase price over fair value of net assets acquired and is presented on the consolidated balance sheets net of accumulated amortization. We account for goodwill under SFAS No. 142, Goodwill and Other Intangible Assets, which was issued by the FASB in July 2001 (see Note 3). SFAS 142 prohibits amortization of goodwill and intangible assets with indefinite useful lives, but instead requires testing for impairment at least annually. SFAS 142 requires that intangible assets with definite useful lives be amortized over their respective estimated useful lives. Beginning January 1, 2002, effective with the adoption of SFAS 142, we no longer record amortization expense related to goodwill.

Environmental Expenditures. We accrue for environmental costs that relate to existing conditions caused by past operations. Environmental costs include initial site surveys and environmental studies of potentially contaminated sites, costs for remediation and restoration of sites determined to be contaminated and ongoing monitoring costs, as well as damages and other costs, when estimable. We monitor the balance of accrued undiscounted environmental liabilities on a regular basis. We record liabilities for environmental costs at a specific site when our liability for such costs is probable and a reasonable estimate of the associated costs can be made. Adjustments to initial estimates are recorded, from time to time, to reflect changing circumstances and estimates based upon additional information developed in subsequent periods. Estimates of our ultimate liabilities associated with environmental costs are particularly difficult to make with certainty due to the number of variables involved, including the early stage of investigation at certain sites, the lengthy time frames required to complete remediation alternatives available and the evolving nature of environmental laws and regulations.

Notes To Consolidated Financial Statements—(Continued)

The following table presents the activity of our environmental reserve for the years ended December 31, 2005, 2004 and 2003 (in thousands):

	Years Ended December 31,		
	2005	2004	2003
Balance at beginning of period	$ 5,037	$ 7,639	$ 7,693
Charges to expense	2,530	5,178	6,824
Deductions and other	(5,120)	(7,780)	(6,878)
Balance at end of period	$ 2,447	$ 5,037	$ 7,639

Natural Gas Imbalances. Gas imbalances occur when gas producers (customers) deliver more or less actual natural gas gathering volumes to our gathering systems than they originally nominated. Actual deliveries are different from nominated volumes due to fluctuations in gas production at the wellhead. If the customers supply more natural gas gathering volumes than they nominated, Val Verde and Jonah record a payable for the amount due to customers and also record a receivable for the same amount due from connecting pipeline transporters or shippers. To the extent that these amounts are not cashed out monthly on Val Verde, if the customers supply less natural gas gathering volumes than they nominated, Val Verde and Jonah record a receivable reflecting the amount due from customers and a payable for the same amount due to connecting pipeline transporters or shippers. We record natural gas imbalances using a mark-to-market approach.

Income Taxes. We are a limited partnership. As such, we are not a taxable entity for federal and state income tax purposes and do not directly pay federal and state income tax. Our taxable income or loss, which may vary substantially from the net income or net loss we report in our consolidated statements of income, is includable in the federal and state income tax returns of each unitholder. Accordingly, no recognition has been given to federal and state income taxes for our operations. The aggregate difference in the basis of our net assets for financial and tax reporting purposes cannot be readily determined as we do not have access to information about each unitholders' tax attributes in the Partnership.

Use of Derivatives. We account for derivative financial instruments in accordance with SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, and SFAS No. 138, *Accounting for Certain Derivative Instruments and Certain Hedging Activities, an amendment of FASB Statement No. 133.* These statements establish accounting and reporting standards requiring that derivative instruments (including certain derivative instruments embedded in other contracts) be recorded on the balance sheet at fair value as either assets or liabilities. The accounting for changes in the fair value of a derivative instrument depends on the intended use of the derivative and the resulting designation, which is established at the inception of a derivative.

Our derivative instruments consist primarily of interest rate swaps and contracts for the purchase and sale of petroleum products in connection with our crude oil marketing activities. Substantially all derivative instruments related to our crude oil marketing activities meet the normal purchases and sales criteria of SFAS 133, as amended, and as such, changes in the fair value of petroleum product purchase and sales agreements are reported on the accrual basis of accounting. SFAS 133 describes normal purchases and sales as contracts that provide for the purchase or sale of something other than a financial instrument or derivative instrument that will be delivered in quantities expected to be used or sold by the reporting entity over a reasonable period in the normal course of business.

For all hedging relationships, we formally document at inception the hedging relationship and its risk-management objective and strategy for undertaking the hedge, the hedging instrument, the item, the nature of the risk being hedged, how the hedging instrument's effectiveness in offsetting the hedged risk will be assessed and a description of the method of measuring ineffectiveness. This process includes linking all derivatives that are designated as fair value or cash flow to specific assets and liabilities on the balance sheet or to specific firm commitments or forecasted transactions. We also formally assess, both at the hedge's inception and on an ongoing basis, whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in fair values or cash flows of hedged items. If it is determined that a derivative is not highly effective as a hedge or that it has ceased to be a highly effective hedge, we discontinue hedge accounting prospectively.

For derivative instruments designated as fair value hedges, gains and losses on the derivative instrument are offset against related results on the hedged item in the statement of income. Changes in the fair value of a derivative that is highly effective and that is designated and qualifies as a fair value hedge, along with the loss or gain on the hedged asset or liability or unrecognized firm commitment of the hedged item that is attributable to the hedged risk, are recorded in earnings. Changes in the fair value of a derivative that is highly effective and that is designated and qualifies as a cash flow hedge are recorded in other comprehensive income to the extent that the derivative is effective as a hedge, until earnings are affected by the variability in cash flows of the designated hedged item. Hedge effectiveness is measured at least quarterly based on the relative cumulative changes in fair value between the derivative contract and the hedged item over time. The ineffective portion of the change in fair value of a derivative instrument that qualifies as either a fair value hedge or a cash flow hedge is reported immediately in earnings.

According to SFAS 133, as amended, we are required to discontinue hedge accounting prospectively when it is determined that the derivative is no longer effective in offsetting changes in the fair value or cash flows of the hedged item, the derivative expires or is sold, terminated, or exercised, the derivative is de-designated as a hedging instrument, because it is unlikely that a forecasted transaction will occur, a hedged firm commitment no longer meets the definition of a firm commitment, or management determines that designation of the derivative as a hedging instrument is no longer appropriate.

When hedge accounting is discontinued because it is determined that the derivative no longer qualifies as an effective fair value hedge, we continue to carry the derivative on the balance sheet at its fair value and no longer adjust the hedged asset or liability for changes in fair value. The adjustment of the carrying amount of the hedged asset or liability is accounted for in the same manner as other components of the carrying amount of that asset or liability. When hedge accounting is discontinued because the hedged item no longer meets the definition of a firm commitment, we continue to carry the derivative on the balance sheet at its fair value, remove any asset or liability that was recorded pursuant to recognition of the firm commitment from the balance sheet, and recognize any gain or loss in earnings. When hedge accounting is discontinued because it is probable that a forecasted transaction will not occur, we continue to carry the derivative on the balance sheet at its fair value with subsequent changes in fair value included in earnings, and gains and losses that were accumulated in other comprehensive income are recognized immediately in earnings. In all other situations in which hedge accounting is discontinued, we continue to carry the derivative at its fair value on the balance sheet and recognize any subsequent changes in its fair value in earnings.

Fair Value of Financial Instruments. The carrying amount of cash and cash equivalents, accounts receivable, inventories, other current assets, accounts payable and accrued liabilities, other current liabilities and derivatives approximates their fair value due to their short-term nature. The fair values of these financial instruments are represented in our consolidated balance sheets.

Net Income Per Unit. Basic net income per Unit is computed by dividing net income, after deduction of the General Partner's interest, by the weighted average number of Units outstanding (a total of 67.4 million Units, 63.0 million Units and 59.8 million Units for the years ended December 31, 2005, 2004 and 2003, respectively). The General Partner's percentage interest in our net income is based on its percentage of cash distributions from Available Cash for each year (see Note 11). The General Partner was allocated $47.6 million (representing 29.27%) of net income for the year ended December 31, 2005, $40.0 million (representing 28.85%) of net income for the year ended December 31, 2004, and $33.7 million (representing 27.65%) of net income for the year ended December 31, 2003. The General Partner's percentage interest in our net income increases as cash distributions paid per Unit increase, in accordance with our limited partnership agreement.

Diluted net income per Unit is similar to the computation of basic net income per Unit discussed above, except that the denominator is increased to include the dilutive effect of outstanding Unit options by application of the treasury stock method. For the year ended December 31, 2003, the denominator was increased by 11,878 Units. For the years ended December 31, 2005 and 2004, diluted net income per Unit equaled basic net income per Unit as all remaining outstanding Unit options were exercised during the third quarter of 2003 (see Note 13).

Unit Option Plan. We have not granted options for any periods presented. For options outstanding under the 1994 Long Term Incentive Plan (see Note 13), we followed the intrinsic value method of accounting for recognizing stock-based compensation expense. Under this method, we record no compensation expense for Unit options granted when the exercise price of the options granted is equal to, or greater than, the market price of our Units on the date of the grant. During the year ended December 31, 2003, all remaining outstanding Unit options were exercised.

In December 2002, SFAS No. 148, *Accounting for Stock-Based Compensation – Transition and Disclosure* was issued. SFAS 148 amends SFAS No. 123, *Accounting for Stock-Based Compensation*, and provides alternative methods of transition for a voluntary change to the fair value based method of accounting for stock-based employee compensation. In addition, SFAS 148 amends the disclosure requirements of SFAS 123 to require prominent disclosure in both annual and interim financial statements about the method of accounting for stock-based employee compensation and the effect of the method used on reported results. Certain of the disclosure modifications are required for fiscal years ending after December 15, 2002, and are included in Note 13.

Assuming we had used the fair value method of accounting for our Unit option plan, pro forma net income would equal reported net income for the years ended December 31, 2005, 2004 and 2003. Pro forma net income per Unit would equal reported net income per Unit for the periods presented. The adoption of SFAS 148 did not have an effect on our financial position, results of operations or cash flows.

New Accounting Pronouncements. In December 2004, the FASB issued SFAS No. 123(R), *Share-Based Payment*. SFAS 123(R) requires compensation costs related to share-based payment transactions to be recognized in the financial statements. With limited exceptions, the amount of the compensation cost is to be measured based on the grant-date fair value of the equity or liability instruments issued. In addition, liability awards are to be re-measured each reporting period. Compensation cost will be recognized over the period that an employee provides service in exchange for the award. SFAS 123(R) is a revision of SFAS No. 123, *Accounting for Stock-Based Compensation*, as amended by SFAS No. 148, *Accounting for Stock-Based Compensation – Transition and Disclosure* and supersedes Accounting Principles Board ("APB") Opinion No. 25, *Accounting for Stock Issued to Employees*. SFAS 123(R) is effective for public companies as of the first interim or annual reporting period of the first fiscal year beginning after June 15, 2005. The Securities and Exchange Commission amended the implementation date of SFAS 123(R) to begin with the first interim or annual reporting period of the company's first fiscal year beginning on or after June 15, 1005. As such, we will adopt SFAS 123(R) in the first quarter of 2006. Companies are permitted to adopt SFAS 123(R) prior to the extended date. All public companies that adopted the fair-value-based method of accounting must use the modified prospective transition method and may elect to use the modified retrospective transition method. We do not believe that the adoption of SFAS 123(R) will have a material effect on our financial position, results of operations or cash flows.

In November 2004, the Emerging Issues Task Force ("EITF") reached consensus in EITF 03-13, *Applying the Conditions in Paragraph 42 of FASB Statement No. 144, Accounting for Impairment or Disposal of Long-Lived Assets, in Determining Whether to Report* Discontinued Operations, to clarify whether a component of an enterprise that is either disposed of or classified as held for sale qualifies for income statement presentation as discontinued operations. The FASB ratified the consensus on November 30, 2004. The consensus is to be applied prospectively with regard to a component of an enterprise that is either disposed of or classified as held for sale in reporting periods beginning after December 15, 2004. The consensus may be applied retrospectively for previously reported operating results related to disposal transactions initiated within an enterprise's reporting period that included the date that this consensus was ratified. The adoption of EITF 03-13 did not have an effect on our financial position, results of operations or cash flows.

In March 2005, the FASB issued FASB Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations, an interpretation of FASB Statement No. 143* ("FIN 47"). FIN 47 clarifies that the term, conditional asset retirement obligation as used in SFAS No. 143, *Accounting for Asset Retirement Obligations*, refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional upon a future event that may or may not be within the control of the entity. Even though uncertainty about the timing and/or method of settlement exists and may be conditional upon a future event, the obligation to perform the asset retirement activity is unconditional. Accordingly, an entity is required to recognize a liability for the fair value of a conditional asset retirement obligation if the fair value of the liability can be reasonably estimated. Uncertainty about the timing and/or method of settlement of a conditional asset retirement obligation should be factored into the measurement of the liability when sufficient information exists. The fair value of a liability for the conditional asset retirement obligation should be recognized when incurred generally upon acquisition, construction, or development or through the normal operation of the asset. SFAS 143 acknowledges that in some cases, sufficient information may not be available to reasonably estimate the fair value of an asset retirement obligation. FIN 47 also clarifies when an entity would have sufficient information to reasonably estimate the fair value of an asset retirement obligation. FIN 47 is effective no later than the end of reporting periods ending after December 15, 2005, and early adoption of FIN 47 is encouraged. We adopted FIN 47 in the fourth quarter of 2005. The adoption of FIN 47 did not have a material effect on our financial position, results of operations or cash flows.

In June 2005, the EITF reached consensus in EITF 04-5, *Determining Whether a General Partner, or the General Partners as a Group, Controls a Limited Partnership or Similar Entity When the Limited Partners Have Certain Rights*, to provide guidance on how general partners in a limited partnership should determine whether they control a limited partnership and therefore should consolidate it. The EITF agreed that the presumption of general partner control would be overcome only when the limited partners have either of two types of rights. The first type, referred to as kick-out rights, is the right to dissolve or liquidate the partnership or otherwise remove the general partner without cause. The second type, referred to as participating rights, is the right to effectively participate in significant decisions made in the ordinary course of the partnership's business. The kick-out rights and the participating rights must be substantive in order to overcome the presumption of general partner control. The consensus is effective for general partners of all new limited partnerships formed and for existing limited partnerships for which the partnership agreements are modified subsequent to the date of FASB ratification (June 29, 2005). For existing limited partnerships that have not been modified, the guidance in EITF 04-5 is effective no later than the beginning of the first reporting period in fiscal years beginning after December 15, 2005. We do not believe that the adoption of EITF 04-5 will have a material effect on our financial position, results of operations or cash flows.

In December 2004, the FASB issued SFAS No. 153, *Exchanges of Nonmonetary Assets, an amendment of APB Opinion 29*. SFAS 153 amends APB Opinion No. 29, Accounting for Nonmonetary Exchanges, to eliminate the exception for nonmonetary exchanges of similar productive assets and replaces it with a general exception for exchanges of nonmonetary assets that do not have commercial substance. A nonmonetary exchange has commercial substance if the future cash flows of the entity are expected to change significantly as a result of the exchange. SFAS 153 is effective for nonmonetary asset exchanges occurring in fiscal periods beginning after June 15, 2005. We adopted SFAS 153 during the second quarter of 2005. The adoption of SFAS 153 did not have a material effect on our financial position, results of operations or cash flows.

In May 2005, the FASB issued SFAS No. 154, *Accounting Changes and Error Corrections*. SFAS 154 establishes new standards on accounting for changes in accounting principles. All such changes must be accounted for by retrospective application to the financial statements of prior periods unless it is impracticable to do so. SFAS 154 completely replaces APB Opinion No. 20, *Accounting Changes*, and SFAS No. 3, *Reporting Accounting Changes in Interim Periods*. However, it carries forward the guidance in those pronouncements with respect to accounting for changes in estimates, changes in the reporting entity, and the correction of errors. SFAS 154 is effective for accounting changes and error corrections made in fiscal years beginning after December 15, 2005, with early adoption permitted for changes and corrections made in years beginning after June 1, 2005. The application of SFAS 154 does not affect the transition provisions of any existing pronouncements, including those that are in the transition phase as of the effective date of SFAS 154. We do not believe that the adoption of SFAS 154 will have a material effect on our financial position, results of operations or cash flows.

In September 2005, the EITF reached consensus in EITF 04-13, *Accounting for Purchases and Sales of Inventory with the Same Counterparty*, to define when a purchase and a sale of inventory with the same party that operates in the same line of business should be considered a single nonmonetary transaction subject to APB Opinion No. 29, *Accounting for Nonmonetary Transactions*. Two or more inventory transactions with the same party should be combined if they are entered into in contemplation of one another. The EITF also requires entities to account for exchanges of inventory in the same line of business at fair value or recorded amounts based on inventory classification. The guidance in EITF 04-13 is effective for new inventory arrangements entered into in reporting periods beginning after March 15, 2006. We are currently evaluating what impact EITF 04-13 will have on our financial statements, but at this time we do not believe that the adoption of EITF 04-13 will have a material effect on our financial position, results of operations or cash flows.

Note 3. Goodwill and Other Intangible Assets

Goodwill. Goodwill represents the excess of purchase price over fair value of net assets acquired and is presented on the consolidated balance sheets net of accumulated amortization. We account for goodwill under SFAS No. 142, *Goodwill and Other Intangible Assets*, which was issued by the FASB in July 2001. SFAS 142 prohibits amortization of goodwill and intangible assets with indefinite useful lives, but instead requires testing for impairment at least annually. We test goodwill and intangible assets for impairment annually at December 31.

To perform an impairment test of goodwill, we have identified our reporting units and have determined the carrying value of each reporting unit by assigning the assets and liabilities, including the existing goodwill and intangible assets, to those reporting units. We then determine the fair value of each reporting unit and compare it to the carrying value of the reporting unit. We will continue to compare the fair value of each reporting unit to its carrying value on an annual basis to determine if an impairment loss has occurred. There have been no goodwill impairment losses recorded since the adoption of SFAS 142.

The following table presents the carrying amount of goodwill at December 31, 2005 and 2004, by business segment (in thousands):

	Downstream Segment	Midstream Segment	Upstream Segment	Segments Total
Goodwill	$ —	$ 2,777	$ 14,167	$ 16,944

Notes To Consolidated Financial Statements—(Continued)

Other Intangible Assets. The following table reflects the components of intangible assets, including excess investments, being amortized at December 31, 2005 and 2004 (in thousands):

	December 31, 2005		December 31, 2004	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Intangible assets:				
Gathering and transportation agreements	$464,337	$ (118,921)	$464,337	$ (91,262)
Fractionation agreement	38,000	(14,725)	38,000	(12,825)
Other	10,226	(2,009)	12,262	(3,154)
Subtotal	$512,563	$ (135,655)	$514,599	$ (107,241)
Excess investments:				
Centennial Pipeline LLC	$ 33,400	$ (12,947)	$ 33,400	$ (8,875)
Seaway Crude Pipeline Company	27,100	(3,764)	27,100	(3,072)
Subtotal	$ 60,500	$ (16,711)	$ 60,500	$ (11,947)
Total intangible assets	$573,063	$ (152,366)	$575,099	$ (119,188)

SFAS 142 requires that intangible assets with finite useful lives be amortized over their respective estimated useful lives If an intangible asset has a finite useful life, but the precise length of that life is not known, that intangible asset shall be amortized over the best estimate of its useful life At a minimum, we will assess the useful lives and residual values of all intangible assets on an annual basis to determine if adjustments are required. Amortization expense on intangible assets was $30 5 million, $32.2 million and $36.2 million for the years ended December 31, 2005, 2004 and 2003, respectively. Amortization expense on excess investments included in equity earnings was $4 8 million, $3.8 million and $4 0 million for the years ended December 31, 2005, 2004 and 2003, respectively

The values assigned to our intangible assets for natural gas gathering contracts on the Jonah and the Val Verde systems are amortized on a unit-of-production basis, based upon the actual throughput of the systems compared to the expected total throughput for the lives of the contracts On a quarterly basis, we may obtain limited production forecasts and updated throughput estimates from some of the producers on the systems, and as a result, we evaluate the remaining expected useful lives of the contract assets based on the best available information. During the fourth quarter of 2004 and the first and second quarters of 2005, certain limited production forecasts were obtained from some of the producers on the Jonah system related to future expansions of the system, and as a result, we increased our best estimate of future throughput on the system, which resulted in extensions in the remaining lives of the intangible assets During the fourth quarter of 2004 and the third quarter of 2005, certain limited coal bed methane production forecasts were obtained from some of the producers on the Val Verde system whose contracts are included in the intangible assets These forecasts indicated lower coal bed methane production estimates over the contract periods, and as a result, we decreased our best estimate of future throughput on the Val Verde system, which resulted in increases to amortization expense on the intangible assets. Further revisions to these estimates may occur as additional production information is made available to us.

The values assigned to our fractionation agreement and other intangible assets are generally amortized on a straight-line basis Our fractionation agreement is being amortized over its contract period of 20 years The amortization periods for our other intangible assets, which include non-compete and other agreements, range from 3 years to 15 years. The value of $8.7 million assigned to our crude supply and transportation intangible customer contracts is being amortized on a unit-of-production basis (see Note 5).

The value assigned to our excess investment in Centennial was created upon its formation. Approximately $30.0 million is related to a contract and is being amortized on a unit-of-production basis based upon the volumes transported under the contract compared to the guaranteed total throughput of the contract over a 10-year life The remaining $3.4 million is related to a pipeline and is being amortized on a straight-line basis over the life of the pipeline, which is 35 years The value assigned to our excess investment in Seaway was created upon acquisition of our 50% ownership interest in 2000. We are amortizing the $27 1 million excess investment in Seaway on a straight-line basis over a 39-year life related primarily to the life of the pipeline

The following table sets forth the estimated amortization expense of intangible assets and the estimated amortization expense allocated to equity earnings for the years ending December 31 (in thousands):

	Intangible Assets	Excess Investments
2006	$ 32,561	$ 4,691
2007	33,395	5,113
2008	32,967	5,438
2009	30,719	6,878
2010	27,338	7,042

Note 4. Interest Rate Swaps

In July 2000, we entered into an interest rate swap agreement to hedge our exposure to increases in the benchmark interest rate underlying our variable rate revolving credit facility. This interest rate swap matured in April 2004 We designated this swap agreement, which hedged exposure to variability in expected future cash flows attributed to changes in interest rates, as a cash flow hedge. The swap agreement was based on a notional amount of $250.0 million. Under the swap agreement, we paid a fixed rate of interest of 6.955% and received a floating rate based on a three-month U.S Dollar LIBOR rate Because this swap was designated as a cash flow hedge, the changes in fair value, to the extent the swap was effective, were recognized in other comprehensive income until the hedged interest costs were recognized in earnings. During the years ended December 31, 2004 and 2003, we recognized an increase in interest expense of $2 9 million and $14 4 million, respectively, related to the difference between the fixed rate and the floating rate of interest on the interest rate swap.

In October 2001, TE Products entered into an interest rate swap agreement to hedge its exposure to changes in the fair value of its fixed rate 7 51% Senior Notes due 2028. We designated this swap agreement as a fair value hedge. The swap agreement has a notional amount of $210.0 million and matures in January 2028 to match the principal and maturity of the TE Products Senior Notes. Under the swap agreement, TE Products pays a floating rate of interest based on a three-month U.S. Dollar LIBOR rate, plus a spread, and receives a fixed rate of interest of 7.51%. During the years ended December 31, 2005, 2004 and 2003, we recognized reductions in interest expense of $5.6 million, $9.6 million and $10 0 million, respectively, related to the difference between the fixed rate and the floating rate of interest on the interest rate swap. During the years ended December 31, 2005, 2004 and 2003, we measured the hedge effectiveness of this interest rate swap and noted that no gain or loss from ineffectiveness was required to be recognized The fair value of this interest rate swap was a loss of approximately $0 9 million at December 31, 2005, and a gain of approximately $3.4 million at December 31, 2004.

During 2002, we entered into interest rate swap agreements, designated as fair value hedges, to hedge our exposure to changes in the fair value of our fixed rate 7 625% Senior Notes due 2012 The swap agreements had a combined notional amount of $500.0 million and matured in 2012 to match the principal and maturity of the Senior Notes. Under the swap agreements, we paid a floating rate of interest based on a U.S. Dollar LIBOR rate, plus a spread, and received a fixed rate of interest of 7.625%. These swap agreements were later terminated in 2002 resulting in gains of $44.9 million. The gains realized from the swap terminations have been deferred as adjustments to the carrying value of the Senior Notes and are being amortized using the effective interest method as reductions to future interest expense over the remaining term of the Senior Notes. At December 31, 2005, the unamortized balance of the deferred gains was $32.4 million In the event of early extinguishment of the Senior Notes, any remaining unamortized gains would be recognized in the consolidated statement of income at the time of extinguishment.

During May 2005, we executed a treasury rate lock agreement with a notional amount of $200.0 million to hedge our exposure to increases in the treasury rate that was to be used to establish the fixed interest rate for a debt offering that was proposed to occur in the second quarter of 2005. During June 2005, the proposed debt offering was cancelled, and the treasury lock was terminated with a realized loss of $2.0 million. The realized loss was recorded as a component of interest expense in the consolidated statements of income in June 2005.

Note 5. Acquisitions, Dispositions and Discontinued Operations

Rancho Pipeline

In connection with our acquisition of crude oil assets in 2000, we acquired an approximate 23 5% undivided joint interest in the Rancho Pipeline, which was a crude oil pipeline system from West Texas to Houston, Texas. In March 2003, the Rancho Pipeline ceased operations, and segments of the pipeline were sold to certain of the owners that previously held undivided interests in the pipeline. We acquired 241 miles of the pipeline in exchange for cash of $5 5 million and our interests in other portions of the Rancho Pipeline. We sold 183 miles of the segment we acquired to other entities for cash and assets valued at approximately $8 5 million We recorded a net gain of $3.9 million on the transactions in the second quarter of 2003. During the third quarter of 2004, we sold our remaining interest in the original Rancho Pipeline system for a net gain of $0.4 million. These gains are included in the gains on sales of assets in our consolidated statements of income in the 2004 period.

Genesis Pipeline

On November 1, 2003, we purchased crude supply and transportation assets along the upper Texas Gulf Coast for $21.0 million from Genesis Crude Oil, L.P. and Genesis Pipeline Texas, L.P. ("Genesis"). The transaction was funded with proceeds from our August 2003 equity offering (see Note 11). We allocated the purchase price, net of liabilities assumed, primarily to property, plant and equipment and intangible assets. The assets acquired included approximately 150 miles of small diameter trunk lines, 26,000 barrels per day of throughput and 12,000 barrels per day of lease marketing and supply business. We have integrated these assets into our South Texas pipeline system, which has allowed us to consolidate gathering and marketing assets in key operating areas in a cost effective manner and will provide future growth opportunities. Accordingly, the results of the acquisition are included in the consolidated financial statements from November 1, 2003.

The following table allocates the estimated fair value of the Genesis assets acquired on November 1, 2003 (in thousands):

Property, plant and equipment	$12,811
Intangible assets	8,742
Other	144
Total assets	21,697
Total liabilities assumed	(687)
Net assets acquired	$21,010

Mexia Pipeline

On March 31, 2005, we purchased crude oil pipeline assets for $7.1 million from BP Pipelines (North America) Inc. ("BP"). The assets include approximately 158 miles of pipeline, which extend from Mexia, Texas, to the Houston, Texas, area and two stations in south Houston with connections to a BP pipeline that originates in south Houston. We funded the purchase through borrowings under our revolving credit facility. We allocated the purchase price to property, plant and equipment, and we accounted for the acquisition of these assets under the purchase method of accounting. We have integrated these assets into our South Texas pipeline system, included in our Upstream Segment, which will allow us to realize synergies within our existing asset base and will provide future growth opportunities.

Crude Oil Storage and Terminaling Assets

On April 1, 2005, we purchased crude oil storage and terminaling assets in Cushing, Oklahoma, from Koch Supply & Trading, L.P. for $35.4 million. The assets consist of eight storage tanks with 945,000 barrels of storage capacity, receipt and delivery manifolds, interconnections to several pipelines, crude oil inventory and approximately 70 acres of land. We funded the purchase through borrowings under our revolving credit facility. We allocated the purchase price to property, plant and equipment and inventory, and we accounted for the acquisition of these assets under the purchase method of accounting. The storage and terminaling assets complement our existing infrastructure in Cushing and strengthen our gathering and marketing business in our Upstream Segment.

Refined Products Terminal and Truck Rack

On July 12, 2005, we purchased a refined products terminal and truck loading rack in North Little Rock, Arkansas, for $6.9 million from ExxonMobil Corporation. The assets include three storage tanks and a two-bay truck loading rack. We funded the purchase through borrowings under our revolving credit facility. We allocated the purchase price to property, plant and equipment and inventory, and we accounted for the acquisition of these assets under the purchase method of accounting. The terminal serves the central Arkansas refined products market and complements our existing Downstream Segment infrastructure in North Little Rock, Arkansas.

Genco Assets

On July 15, 2005, we acquired from Texas Genco, LLC ("Genco") all of its interests in certain companies that own a 90-mile pipeline system and 5.5 million barrels of storage capacity for $62.1 million. We funded the purchase through borrowings under our revolving credit facility. We allocated the purchase price to property, plant and equipment, and we accounted for the acquisition of these assets under the purchase method of accounting. The assets of the purchased companies will be integrated into our Downstream Segment

Notes To Consolidated Financial Statements—(Continued)

origin infrastructure in Texas City and Baytown, Texas. As a result of this acquisition, we initiated the expansion of refined products origin capabilities in the Houston and Texas City, Texas, areas. The integration and other system enhancements should be in service by the fourth quarter of 2006, at an estimated cost of $45.0 million. The strategic location of these assets, with refined products interconnections to major exchange terminals in the Houston area, will provide significant long-term value to our customers and our Texas Gulf Coast refining and logistics system.

Pioneer Plant

On January 26, 2006, we announced the execution of a letter of intent to sell our ownership interest in the Pioneer silica gel natural gas processing plant located near Opal, Wyoming, together with Jonah's rights to process natural gas originating from the Jonah and Pinedale fields, located in southwest Wyoming, to an affiliate of Enterprise Products Partners L P. ("Enterprise"). On March 31, 2006, we sold the Pioneer plant to an affiliate of Enterprise for $38.0 million in cash. The Pioneer plant, included in our Midstream Segment, was not an integral part of our operations and natural gas processing is not a core business. The Pioneer plant was constructed as part of the Phase III expansion of the Jonah system and was completed during the first quarter of 2004. We have no continuing involvement in the operations or results of this plant. This transaction was reviewed and approved by the Audit and Conflicts Committee of the board of directors of our General Partner and of the general partner of Enterprise, and a fairness opinion was rendered by an independent third-party.

Condensed statements of income for the Pioneer plant, which is classified as discontinued operations, for the years ended December 31, 2005 and 2004, are presented below (in thousands):

	Years Ended December 31,	
	2005	2004
Sales of petroleum products	$10,479	$ 7,295
Other	2,975	2,807
Total operating revenues	13,454	10,102
Purchases of petroleum products	8,870	5,944
Operating, general and administrative	692	738
Depreciation and amortization	612	610
Taxes—other than income taxes	130	121
Total costs and expenses	10,304	7,413
Income from discontinued operations	$ 3,150	$ 2,689

Assets of the discontinued operations consisted of the following at December 31, 2005 and 2004 (in thousands):

	December 31,	
	2005	2004
Inventories	$ 7	$ 28
Property, plant and equipment, net	19,812	20,598
Assets of discontinued operations	$ 19,819	$20,626

Net cash flows from discontinued operations for the years ended December 31, 2005 and 2004, are presented below (in thousands):

	Years Ended December 31,		
	2005	2004	2003
Cash flows from discontinued operating activities:			
Net income	$3,150	$ 2,689	$ —
Depreciation and amortization	612	610	—
(Increase) decrease in inventories	20	(28)	—
Net cash flows provided by discontinued operating activities	3,782	3,271	—
Cash flows from discontinued investing activities:			
Capital expenditures	—	(7,398)	(13,810)
Net cash flows used in discontinued investing activities	—	(7,398)	(13,810)
Net cash flows from discontinued operations	$3,782	$(4,127)	$(13,810)

Note 6. Equity Investments

Through one of our indirect wholly owned subsidiaries, we own a 50% ownership interest in Seaway. The remaining 50% interest is owned by ConocoPhillips. We operate the Seaway assets. Seaway owns a pipeline that carries mostly imported crude oil from a marine terminal at Freeport, Texas, to Cushing, Oklahoma, and from a marine terminal at Texas City, Texas, to refineries in the Texas City and Houston, Texas, areas. The Seaway Crude Pipeline Company Partnership Agreement provides for varying participation ratios throughout the life of Seaway. From June 2002 through May 2006, we receive 60% of revenue and expense of Seaway. Thereafter, we will receive 40% of revenue and expense of Seaway. During the years ended December 31, 2005, 2004 and 2003, we received distributions from Seaway of $24.7 million, $36.9 million and $22.7 million, respectively.

In August 2000, TE Products entered into agreements with Panhandle Eastern Pipeline Company ("PEPL"), a former subsidiary of CMS Energy Corporation, and Marathon Petroleum Company LLC ("Marathon") to form Centennial. Centennial owns an interstate refined petroleum products pipeline extending from the upper Texas Gulf Coast to central Illinois. Through February 9, 2003, each participant owned a one-third interest in Centennial. On February 10, 2003, TE Products and Marathon each acquired an additional 16.7% interest in Centennial from PEPL for $20.0 million each, increasing their ownership percentages in Centennial to 50% each. During the year ended December 31, 2005, TE Products did not make any additional investments in Centennial. TE Products invested an additional $1.5 million and $24.0 million, respectively, in Centennial, in 2004 and 2003, which is included in the equity investment balance at December 31, 2005. The 2003 amount includes the $20.0 million paid for the acquisition of the additional ownership interest in Centennial. TE Products has not received any distributions from Centennial since its formation.

On January 1, 2003, TE Products and Louis Dreyfus Energy Services L.P. ("Louis Dreyfus") formed Mont Belvieu Storage Partners, L.P. ("MB Storage"). TE Products and Louis Dreyfus each own a 50% ownership interest in MB Storage. MB Storage owns storage capacity at the Mont Belvieu fractionation and storage complex and a short haul transportation shuttle system that ties Mont Belvieu, Texas, to the upper Texas Gulf Coast energy marketplace. MB Storage is a service-oriented, fee-based venture serving the fractionation, refining and petrochemical industries with substantial capacity and flexibility for the transportation, terminaling and storage of NGLs, LPGs and refined products. MB Storage has no commodity trading activity. TE Products operates the facilities for MB Storage. Effective January 1, 2003, TE Products contributed property and equipment with a net book value of $67.1 million to MB Storage. Additionally, as of the contribution date, Louis Dreyfus had invested $6.1 million for expansion projects for MB Storage that TE Products was required to reimburse if the original joint development and marketing agreement was terminated by either party. This deferred liability was also contributed and credited to the capital account of Louis Dreyfus in MB Storage.

For the year ended December 31, 2005, TE Products received the first $1.7 million per quarter (or $6.78 million on an annual basis) of MB Storage's income before depreciation expense, as defined in the operating agreement. For the year ended December 31, 2004, TE Products received the first $1.8 million per quarter (or $7.15 million on an annual basis) of MB Storage's income before depreciation expense. TE Products' share of MB Storage's earnings is adjusted annually by the partners of MB Storage. Any amount of MB Storage's annual income before depreciation expense in excess of $6.78 million for 2005 and $7.15 million for 2004 was allocated evenly between TE Products and Louis Dreyfus. Depreciation expense on assets each party originally contributed to MB Storage is allocated between TE Products and Louis Dreyfus based on the net book value of the assets contributed. Depreciation expense on assets constructed or acquired by MB Storage subsequent to formation is allocated evenly between TE Products and Louis Dreyfus. For the years ended December 31, 2005, 2004 and 2003, TE Products' sharing ratio in the earnings of MB Storage was 64.2%, 69.4% and 70.4%, respectively. During the years ended December 31, 2005, 2004 and 2003, TE Products received distributions of $12.4 million, $10.3 million and $5.3 million, respectively, from MB Storage. During the years ended December 31, 2005, 2004 and 2003, TE Products contributed $5.6 million, $21.4 million and $2.5 million, respectively, to MB Storage. The 2005 contribution includes a combination of non-cash asset transfers of $1.4 million and cash contributions of $4.2 million. The 2004 contribution includes $16.5 million for the acquisition of storage and pipeline assets in April 2004. The remaining contributions have been for capital expenditures.

We use the equity method of accounting to account for our investments in Seaway, Centennial and MB Storage. Summarized combined financial information for Seaway, Centennial and MB Storage for the years ended December 31, 2005 and 2004, is presented below (in thousands):

	Years Ended December 31, 2005	Years Ended December 31, 2004
Revenues	$ 164,494	$ 149,843
Net income	52,623	52,059

Summarized combined balance sheet information for Seaway, Centennial and MB Storage as of December 31, 2005 and 2004, is presented below (in thousands):

	December 31,	
	2005	2004
Current assets	$ 60,082	$ 59,314
Noncurrent assets	630,212	633,222
Current liabilities	42,242	41,209
Long-term debt	140,000	140,000
Noncurrent liabilities	13,626	20,440
Partners' capital	494,426	490,887

Note 7. Related Party Transactions

EPCO and Affiliates and Duke Energy, DEFS and Affiliates

The Partnership does not have any employees. We are managed by the Company, which, for all periods prior to February 23, 2005, was an indirect wholly owned subsidiary of DEFS. According to the Partnership Agreement, the Company was entitled to reimbursement of all direct and indirect expenses related to our business activities As a result of the change in ownership of the General Partner on February 24, 2005, all of our management, administrative and operating functions are performed by employees of EPCO, pursuant to an administrative services agreement. We reimburse EPCO for the costs of its employees who perform operating functions for us and for costs related to its other management and administrative employees (see Note 1).

The following table summarizes the related party transactions with EPCO and affiliates and DEFS and affiliates for the periods indicated (in millions):

	Years Ended December 31,		
	2005	2004	2003
Revenues from EPCO and affiliates[1]			
Transportation—NGLs[2]	$ 7.4	$ —	$ —
Transportation—LPGs[3]	4.3	—	—
Other operating revenues[4]	0.3	—	—
Costs and Expenses from EPCO and affiliates[1]			
Payroll and administrative[5]	68.2	—	—
Purchases of petroleum products[6]	3.4	—	—
Revenues from DEFS and affiliates[7]			
Sales of petroleum products[8]	4.3	23.2	15.2
Transportation—NGLs[9]	2.8	16.7	17.2
Gathering—Natural gas—Jonah[10]	0.5	3.3	2.0
Transportation—LPGs[11]	0.7	2.6	2.8
Other operating revenues[12]	2.4	14.0	10.8
Costs and Expenses from DEFS and affiliates[7] [13] [14]			
Payroll and administrative[5]	16.2	95.9	88.8
Purchases of petroleum products—TCO[15]	37.7	141.3	110.7
Purchases of petroleum products—Jonah[16]	0.8	5.1	—

(1) Operating revenues earned and expenses incurred from activities with EPCO and its affiliates are considered related party transactions from February 24, 2005, through December 31, 2005, as a result of the change in ownership of the General Partner (see Note 1).

(2) Includes revenues from NGL transportation on the Chaparral and Panola NGL pipelines.

(3) Includes revenues from LPG transportation on the TE Products pipeline.

(4) Includes other operating revenues on TE Products.

(5) Substantially all of these costs were related to payroll, payroll related expenses and administrative expenses incurred in managing us and our subsidiaries.

(6) Includes TCO purchases of condensate and expenses related to LSI's use of an affiliate of EPCO as a transporter.

(7) Operating revenues earned and expenses incurred from activities with DEFS and its affiliates are considered related party transactions for all periods through February 23, 2005, as a result of the change in ownership of the General Partner (see Note 1).

(8) Includes LSI sales of lubrication oils and specialty chemicals and Jonah NGL sales in connection with Jonah's Pioneer processing plant operations, which was constructed during the Phase III expansion and began operating in 2004. Amounts related to the Pioneer plant are classified as discontinued operations in the consolidated statements of income.

(9) Includes revenues from NGL transportation on the Chaparral, Panola, Dean and Wilcox NGL pipelines.

(10) Includes gas gathering revenues on the Jonah system.

(11) Effective May 2001, we entered into an agreement with an affiliate of DEFS to commit to it sole utilization of our Providence, Rhode Island, terminal. We operate the terminal and provide propane loading services to an affiliate of DEFS. We recognized revenue from an affiliate of DEFS pursuant to this agreement.

(12) Includes fractionation revenues and other revenues. Effective with the purchase of the fractionation facilities on March 31, 1998, TEPPCO Colorado and DEFS entered into a 20-year Fractionation Agreement, under which TEPPCO Colorado receives a variable fee for all fractionated volumes delivered to DEFS. Other operating revenues also include other operating revenues on TE Products and processing and other revenues on the Jonah system. Amounts related to the Pioneer plant are classified as discontinued operations in the consolidated statements of income.

(13) Includes operating costs and expenses related to DEFS managing and operating the Jonah and Val Verde systems and the Chaparral NGL pipeline on our behalf under a contractual agreement established at the time of acquisition of each asset. In connection with the change in ownership of our General Partner, we have assumed these activities

(14) Effective with the purchase of the fractionation facilities on March 31, 1998, TEPPCO Colorado and DEFS entered into an Operation and Maintenance Agreement, whereby DEFS operates and maintains the fractionation facilities for TEPPCO Colorado. For these services, TEPPCO Colorado pays DEFS a set volumetric rate for all fractionated volumes delivered to DEFS

(15) Includes TCO purchases of condensate.

(16) Includes Jonah purchases of natural gas in connection with Jonah's Pioneer processing plant operations.

At December 31, 2005, we had a receivable from EPCO and affiliates of $4.3 million related to sales and transportation services provided to EPCO and affiliates. At December 31, 2005, we had a payable to EPCO and affiliates of $9.8 million related to direct payroll, payroll related costs and other operational related charges.

At December 31, 2004, we had a receivable from DEFS and affiliates of $10.5 million related to sales and transportation services provided to DEFS and affiliates. Included in this receivable balance from DEFS and affiliates at December 31, 2004, is a gas imbalance receivable of $0.9 million. At December 31, 2004, we had a payable to DEFS and affiliates of $22.4 million related to direct payroll, payroll related costs, management fees, and other operational related charges, including those for Jonah, Chaparral and Val Verde as described above. Included in this payable balance at December 31, 2004, is a gas imbalance payable to DEFS and affiliates of $3.2 million.

From February 24, 2005 through December 31, 2005, the majority of our insurance coverage, including property, liability, business interruption, auto and directors and officers' liability insurance, was obtained through EPCO. From February 24, 2005 through December 31, 2005, we incurred insurance expense related to premiums charged by EPCO of $9.8 million. At December 31, 2005, we had insurance reimbursement receivables due from EPCO of $1.3 million.

Through February 23, 2005, we contracted with Bison Insurance Company Limited ("Bison"), a wholly owned subsidiary of Duke Energy, for a majority of our insurance coverage, including property, liability, auto and directors and officers' liability insurance. Through February 23, 2005 and for the years ended December 31, 2004 and 2003, we incurred insurance expense related to premiums paid to Bison of $1.2 million, $6.5 million and $5.9 million, respectively. At December 31, 2004, we had insurance reimbursement receivables due from Bison of $5.2 million.

On April 2, 2003, we sold in an underwritten public offering 3.9 million Units at $30.35 per Unit. The proceeds from the offering, net of underwriting discount, totaled approximately $114.5 million, of which approximately $113.8 million was used to repurchase and retire all of the 3.9 million previously outstanding Class B Units held by DETTCO (see Note 11)

Seaway

We own a 50% ownership interest in Seaway, and the remaining 50% interest is owned by ConocoPhillips (see Note 6). We operate the Seaway assets. During the years ended December 31, 2005, 2004 and 2003, we billed Seaway $8.5 million, $7.6 million and $7.4 million, respectively, for direct payroll and payroll related expenses for operating Seaway. Additionally, for each of the years ended December 31, 2005, 2004 and 2003, we billed Seaway $2.1 million for indirect management fees for operating Seaway. At December 31, 2005 and 2004, we had payable balances to Seaway of $0.6 million and $0.5 million, respectively, for advances Seaway paid to us as operator for operating costs, including payroll and related expenses and management fees

Centennial

TE Products has a 50% ownership interest in Centennial (see Note 6). TE Products has entered into a management agreement with Centennial to operate Centennial's terminal at Creal Springs, Illinois, and pipeline connection in Beaumont, Texas. For each of the years ended December 31, 2005, 2004 and 2003, we recognized management fees of $0.2 million from Centennial, and actual operating expenses billed to Centennial were $3.7 million, $6.9 million and $4.4 million, respectively.

TE Products also has a joint tariff with Centennial to deliver products at TE Products' locations using Centennial's pipeline as part of the delivery route to connecting carriers. TE Products, as the delivering pipeline, invoices the shippers for the entire delivery rate, records only the net rate attributable to it as transportation revenues and records a liability for the amounts due to Centennial for its share of the tariff. In addition, TE Products performs ongoing construction services for Centennial and bills Centennial for labor and other costs to perform the construction. At December 31, 2005 and 2004, we had net payable balances of $1.4 million and $1.7 million, respectively, to Centennial for its share of the joint tariff deliveries and other operational related charges, partially offset by the reimbursement due to us for construction services provided to Centennial.

In January 2003, TE Products entered into a pipeline capacity lease agreement with Centennial for a period of five years that contains a minimum throughput requirement. For the years ended December 31, 2005, 2004 and 2003, TE Products incurred $5.9 million, $5.3 million and $3.8 million, respectively, of rental charges related to the lease of pipeline capacity on Centennial.

MB Storage

Effective January 1, 2003, TE Products entered into agreements with Louis Dreyfus to form MB Storage (see Note 6). TE Products operates the facilities for MB Storage. TE Products and MB Storage have entered into a pipeline capacity lease agreement, and for each of the years ended December 31, 2005, 2004 and 2003, TE Products recognized $0.1 million in rental revenue related to this lease agreement. During the years ended December 31, 2005, 2004 and 2003, TE Products also billed MB Storage $3.6 million, $3.2 million and $2.5 million, respectively, for direct payroll and payroll related expenses for operating MB Storage. At December 31, 2005 and 2004, TE Products had net receivable balances from MB Storage of $0 9 million and $1 3 million, respectively, for operating costs, including payroll and related expenses for operating MB Storage.

Note 8. Inventories

Inventories are valued at the lower of cost (based on weighted average cost method) or market. The costs of inventories did not exceed market values at December 31, 2005 and 2004. The major components of inventories were as follows (in thousands):

	December 31,	
	2005	2004
Crude oil	$ 3,021	$ 3,690
Refined products	4,461	5,665
LPGs	7,403	—
Lubrication oils and specialty chemicals	5,740	4,002
Materials and supplies	8,203	6,135
Other	241	29
Total	$ 29,069	$19,521

Note 9. Property, Plant and Equipment

Major categories of property, plant and equipment for the years ended December 31, 2005 and 2004, were as follows (in thousands):

	December 31,	
	2005	2004
Land and right of way	$ 147,064	$ 135,984
Line pipe and fittings	1,434,392	1,344,193
Storage tanks	189,054	140,690
Buildings and improvements	51,596	41,205
Machinery and equipment	370,439	333,363
Construction work in progress	241,855	115,937
Total property, plant and equipment	$ 2,434,400	$ 2,111,372
Less accumulated depreciation and amortization	474,332	407,670
Net property, plant and equipment	$ 1,960,068	$ 1,703,702

Depreciation expense, including impairment charges, on property, plant and equipment was $80.8 million, $80.7 million and $64.5 million for the years ended December 31, 2005, 2004 and 2003, respectively. During the fourth quarter of 2004, we wrote off approximately $2.1 million in assets taken out of service to depreciation expense.

In September 2005, our Todhunter facility, near Middletown, Ohio, experienced a propane release and fire at a dehydration unit within the storage facility. The facility is included in our Downstream Segment. The dehydration unit was destroyed due to the propane release and fire, and as a result, we wrote off the remaining book value of the asset of $0.8 million to depreciation and amortization expense during the third quarter of 2005

We evaluate impairment of long-lived assets in accordance with SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*. During the third quarter of 2005, our Upstream Segment was notified by a connecting carrier that the flow of its pipeline system would be reversed, which would directly impact the viability of one of our pipeline systems. This system, located in East Texas, consists of approximately 45 miles of pipeline, six tanks of various sizes and other equipment and asset costs. As a result of changes to the connecting carrier, we performed an impairment test of the system and recorded a $1 8 million non-cash impairment charge, included in depreciation and amortization expense in our consolidated statements of income, for the excess carrying value over the estimated fair value of the system.

During the third quarter of 2005, we completed an evaluation of a crude oil system included in our Upstream Segment. The system, located in Oklahoma, consists of approximately six miles of pipelines, tanks and other equipment and asset costs. The usage of the system has declined in recent months as a result of shifting crude oil production into areas not supported by the system, and as such, it has become more economical to transport barrels by truck to our other pipeline systems. As a result, we performed an impairment test on the system and recorded a $0.8 million non-cash impairment charge, included in depreciation and amortization expense in our consolidated statements of income, for the excess carrying value over the estimated fair value of the system.

During the third quarter of 2004, we completed an evaluation of our marine terminal facility in the Beaumont, Texas, area. The facility consists primarily of a barge dock, a ship dock, four storage tanks and various segments of connecting pipelines and is included in our Downstream Segment. The evaluation indicated that the docks and other assets at the facility needed extensive work to continue to be commercially operational. As a result, we performed an impairment test on the entire marine facility and recorded a $4.4 million non-cash impairment charge, included in depreciation and amortization expense in our consolidated statements of income, for the excess carrying value over the estimated fair value of the facility.

Note 10. Debt

Senior Notes. On January 27, 1998, TE Products completed the issuance of $180.0 million principal amount of 6.45% Senior Notes due 2008, and $210.0 million principal amount of 7.51% Senior Notes due 2028 (collectively the "TE Products Senior Notes"). The 6.45% TE Products Senior Notes were issued at a discount of $0.3 million and are being accreted to their face value over the term of the notes. The 6.45% TE Products Senior Notes due 2008 are not subject to redemption prior to January 15, 2008. The 7.51% TE Products Senior Notes due 2028, issued at par, may be redeemed at any time after January 15, 2008, at the option of TE Products, in whole or in part, at our election at the following redemption prices (expressed in percentages of the principal amount) if redeemed during the twelve months beginning January 15 of the years indicated:

Year	Redemption Price	Year	Redemption Price
2008	103.755%	2013	101.878%
2009	103.380%	2014	101.502%
2010	103.004%	2015	101.127%
2011	102.629%	2016	100.751%
2012	102.253%	2017	100.376%

and thereafter at 100% of the principal amount, together in each case with accrued interest at the redemption date.

The TE Products Senior Notes do not have sinking fund requirements. Interest on the TE Products Senior Notes is payable semiannually in arrears on January 15 and July 15 of each year. The TE Products Senior Notes are unsecured obligations of TE Products and rank pari passu with all other unsecured and unsubordinated indebtedness of TE Products. The indenture governing the TE Products Senior Notes contains covenants, including, but not limited to, covenants limiting the creation of liens securing indebtedness and sale and leaseback transactions. However, the indenture does not limit our ability to incur additional indebtedness. As of December 31, 2005, TE Products was in compliance with the covenants of the TE Products Senior Notes.

On February 20, 2002, we completed the issuance of $500.0 million principal amount of 7.625% Senior Notes due 2012. The 7.625% Senior Notes were issued at a discount of $2.2 million and are being accreted to their face value over the term of the notes. The Senior Notes may be redeemed at any time at our option with the payment of accrued interest and a make-whole premium determined by discounting remaining interest and principal payments using a discount rate equal to the rate of the United States Treasury securities of comparable remaining maturity plus 35 basis points. The indenture governing our 7.625% Senior Notes contains covenants, including, but not limited to, covenants limiting the creation of liens securing indebtedness and sale and leaseback transactions. However, the indenture does not limit our ability to incur additional indebtedness. As of December 31, 2005, we were in compliance with the covenants of these Senior Notes.

On January 30, 2003, we completed the issuance of $200.0 million principal amount of 6.125% Senior Notes due 2013. The 6.125% Senior Notes were issued at a discount of $1.4 million and are being accreted to their face value over the term of the notes. The Senior Notes may be redeemed at any time at our option with the payment of accrued interest and a make-whole premium determined by discounting remaining interest and principal payments using a discount rate equal to the rate of the United States Treasury securities of comparable remaining maturity plus 35 basis points. The indenture governing our 6.125% Senior Notes contains covenants, including, but not limited to, covenants limiting the creation of liens securing indebtedness and sale and leaseback transactions. However, the indenture does not limit our ability to incur additional indebtedness. As of December 31, 2005, we were in compliance with the covenants of these Senior Notes

The following table summarizes the estimated fair values of the Senior Notes as of December 31, 2005 and 2004 (in millions):

	Face	Fair Value December 31,	
	Value	2005	2004
6.45% TE Products Senior Notes, due January 2008	$180.0	$183.7	$187.1
7.625% Senior Notes, due February 2012	500.0	552.0	569.6
6.125% Senior Notes, due February 2013	200.0	205.6	210.2
7.51% TE Products Senior Notes, due January 2028	210.0	224.1	225.6

We have entered into interest rate swap agreements to hedge our exposure to changes in the fair value on a portion of the Senior Notes discussed above (see Note 4).

Revolving Credit Facility. On April 6, 2001, we entered into a $500.0 million revolving credit facility including the issuance of letters of credit of up to $20.0 million ("Three Year Facility"). The interest rate was based, at our option, on either the lender's base rate plus a spread, or LIBOR plus a spread in effect at the time of the borrowings. The credit agreement for the Three Year Facility contained certain restrictive financial covenant ratios. During the first quarter of 2003, we repaid $182.0 million of the outstanding balance of the Three Year Facility with proceeds from the issuance of our 6.125% Senior Notes on January 30, 2003. On June 27, 2003, we repaid the outstanding balance under the Three Year Facility with borrowings under a new credit facility, and canceled the Three Year Facility.

On June 27, 2003, we entered into a $550.0 million unsecured revolving credit facility with a three year term, including the issuance of letters of credit of up to $20.0 million ("Revolving Credit Facility"). The interest rate is based, at our option, on either the lender's base rate plus a spread, or LIBOR plus a spread in effect at the time of the borrowings. The credit agreement for the Revolving Credit Facility contains certain restrictive financial covenant ratios. Restrictive covenants in the Revolving Credit Facility limit our ability to, among other things, incur additional indebtedness, make distributions in excess of Available Cash (see Note 11) and complete mergers, acquisitions and sales of assets. We borrowed $263.0 million under the Revolving Credit Facility and repaid the outstanding balance of the Three Year Facility. On October 21, 2004, we amended our Revolving Credit Facility to (i) increase the facility size to $600.0 million, (ii) extend the term to October 21, 2009, (iii) remove certain restrictive covenants, (iv) increase the available amount for the issuance of letters of credit up to $100.0 million and (v) decrease the LIBOR rate spread charged at the time of each borrowing. On February 23, 2005, we amended our Revolving Credit Facility to remove the requirement that DEFS must at all times own, directly or indirectly, 100% of our General Partner, to allow for its acquisition by DFI (see Note 1). During the second quarter of 2005, we used a portion of the proceeds from the equity offering in May 2005 to repay a portion of the Revolving Credit Facility (see Note 11). On December 13, 2005, we again amended our Revolving Credit Facility as follows:

- Total bank commitments increased from $600.0 million to $700.0 million. The amendment also provided that the commitments under the credit facility may be increased up to a maximum of $850.0 million upon our request, subject to lender approval and the satisfaction of certain other conditions.
- The facility fee and the borrowing rate currently in effect were reduced by 0.275%.
- The maturity date of the credit facility was extended from October 21, 2009, to December 13, 2010. Also under the terms of the amendment, we may request up to two, one-year extensions of the maturity date. These extensions, if requested, will become effective subject to lender approval and satisfaction of certain other conditions
- The amendment also removed the $100.0 million limit on the total amount of standby letters of credit that can be outstanding under the credit facility.

On December 31, 2005, $405.9 million was outstanding under the Revolving Credit Facility at a weighted average interest rate of 4.9%. At December 31, 2005, we were in compliance with the covenants of this credit agreement.

Notes To Consolidated Financial Statements—(Continued)

The following table summarizes the principal amounts outstanding under all of our credit facilities as of December 31, 2005 and 2004 (in thousands):

	December 31, 2005	December 31, 2004
Credit Facilities:		
Revolving Credit Facility, due December 2010	$ 405,900	$ 353,000
6.45% TE Products Senior Notes, due January 2008	179,937	179,906
7.625% Senior Notes, due February 2012	498,659	498,438
6.125% Senior Notes, due February 2013	198,988	198,845
7.51% TE Products Senior Notes, due January 2028	210,000	210,000
Total borrowings	1,493,484	1,440,189
Adjustment to carrying value associated with hedges of fair value	31,537	40,037
Total Credit Facilities	$ 1,525,021	$ 1,480,226

~~**Letter of Credit.** At December 31, 2005, we had an $11.5 million standby letter of credit in connection with crude oil purchases in the fourth quarter of 2005. This amount~~ will be paid during the first quarter of 2006.

Note 11. Partners' Capital and Distributions

Equity Offerings

On April 2, 2003, we sold in an underwritten public offering 3.9 million Units at $30.35 per Unit. The proceeds from the offering, net of underwriting discount, totaled approximately $114.5 million, of which approximately $113.8 million was used to repurchase and retire all of the 3.9 million previously outstanding Class B Units held by DETTCO. We received approximately $0.7 million in proceeds from the offering in excess of the amount needed to repurchase and retire the Class B Units.

On August 7, 2003, we sold in an underwritten public offering 5.0 million Units at $34.68 per Unit. The proceeds from the offering, net of underwriting discount, totaled approximately $166.0 million. On August 19, 2003, 162,900 Units were sold upon exercise of the underwriters' over-allotment option granted in connection with the offering on August 7, 2003. Proceeds from the over-allotment sale, net of underwriting discount, totaled $5.4 million. Approximately $53.0 million of the proceeds were used to repay indebtedness under our revolving credit facility and $21.0 million was used to fund the acquisition of the Genesis assets (see Note 5). The remaining amount was used primarily to fund revenue-generating and system upgrade capital expenditures and for general partnership purposes.

On May 5, 2005, we sold in an underwritten public offering 6.1 million Units at $41.75 per Unit. The proceeds from the offering, net of underwriting discount, totaled approximately $244.5 million. On June 8, 2005, 865,000 Units were sold upon exercise of the underwriters' over-allotment option granted in connection with the offering on May 5, 2005. Proceeds from the over-allotment sale, net of underwriting discount, totaled $34.7 million. The proceeds were used to reduce indebtedness under our Revolving Credit Facility, to fund revenue generating and system upgrade capital expenditures and for general partnership purposes.

Quarterly Distributions of Available Cash

We make quarterly cash distributions of all of our Available Cash, generally defined as consolidated cash receipts less consolidated cash disbursements and cash reserves established by the General Partner in its sole discretion. Pursuant to the Partnership Agreement, the General Partner receives incremental incentive cash distributions when unitholders' cash distributions exceed certain target thresholds as follows:

	Unitholders	General Partner
Quarterly Cash Distribution per Unit:		
Up to Minimum Quarterly Distribution ($0.275 per Unit)	98%	2%
First Target—$0.276 per Unit up to $0.325 per Unit	85%	15%
Second Target—$0.326 per Unit up to $0.45 per Unit	75%	25%
Over Second Target—Cash distributions greater than $0.45 per Unit	50%	50%

TEPPCO PARTNERS, L.P.

Notes To Consolidated Financial Statements—(Continued)

The following table reflects the allocation of total distributions paid during the years ended December 31, 2005, 2004 and 2003 (in thousands, except per Unit amounts):

	Years Ended December 31,		
	2005	2004	2003
Limited Partner Units	$ 177,917	$ 166,158	$ 145,427
General Partner Ownership Interest	3,630	3,391	3,016
General Partner Incentive	69,554	63,508	51,709
Total Partners' Capital Cash Distributions Paid	251,101	233,057	200,152
Class B Units	—	—	2,346
Total Cash Distributions Paid	$ 251,101	$ 233,057	$ 202,498
Total Cash Distributions Paid Per Unit	$ 2.68	$ 2.64	$ 2.50

On February 7, 2006, we paid a cash distribution of $0.675 per Unit for the quarter ended December 31, 2005. The fourth quarter 2005 cash distribution totaled $66.9 million.

General Partner Interest

As of December 31, 2005 and 2004, we had deficit balances of $61.5 million and $35.9 million, respectively, in our General Partner's equity account. These negative balances do not represent an asset to us and do not represent an obligation of the General Partner to contribute cash or other property to us. The General Partner's equity account generally consists of its cumulative share of our net income less cash distributions made to it plus capital contributions that it has made to us (see our Consolidated Statements of Partners' Capital for a detail of the General Partner's equity account). For the years ended December 31, 2005, 2004 and 2003, the General Partner was allocated $47.6 million (representing 29.27%), $40.0 million (representing 28.85%) and $33.7 million (representing 27.65%), respectively, of our net income and received $73.2 million, $66.9 million and $54.7 million, respectively, in cash distributions.

Capital Accounts, as defined under our Partnership Agreement, are maintained for our General Partner and our limited partners. The Capital Account provisions of our Partnership Agreement incorporate principles established for U.S. federal income tax purposes and are not comparable to the equity accounts reflected under accounting principles generally accepted in the United States in our financial statements. Under our Partnership Agreement, the General Partner is required to make additional capital contributions to us upon the issuance of any additional Units if necessary to maintain a Capital Account balance equal to 1.999999% of the total Capital Accounts of all partners. At December 31, 2005 and 2004, the General Partner's Capital Account balance substantially exceeded this requirement.

Net income is allocated between the General Partner and the limited partners in the same proportion as aggregate cash distributions made to the General Partner and the limited partners during the period. This is generally consistent with the manner of allocating net income under our Partnership Agreement. Net income determined under our Partnership Agreement, however, incorporates principles established for U.S. federal income tax purposes and is not comparable to net income reflected under accounting principles generally accepted in the United States in our financial statements.

Cash distributions that we make during a period may exceed our net income for the period. We make quarterly cash distributions of all of our Available Cash, generally defined as consolidated cash receipts less consolidated cash disbursements and cash reserves established by the General Partner in its sole discretion. Cash distributions in excess of net income allocations and capital contributions during the years ended December 31, 2005 and 2004, resulted in a deficit in the General Partner's equity account at December 31, 2005 and 2004. Future cash distributions that exceed net income will result in an increase in the deficit balance in the General Partner's equity account.

According to the Partnership Agreement, in the event of our dissolution, after satisfying our liabilities, our remaining assets would be divided among our limited partners and the General Partner generally in the same proportion as Available Cash but calculated on a cumulative basis over the life of the Partnership. If a deficit balance still remains in the General Partner's equity account after all allocations are made between the partners, the General Partner would not be required to make whole any such deficit.

Note 12. Concentrations of Credit Risk

Our primary market areas are located in the Northeast, Midwest and Southwest regions of the United States. We have a concentration of trade receivable balances due from major integrated oil companies, independent oil companies and other pipelines and wholesalers. These concentrations of customers may affect our overall credit risk in that the customers may be similarly affected by changes in economic, regulatory or other factors We thoroughly analyze our customers' historical and future credit positions prior to extending credit. We manage our exposure to credit risk through credit analysis, credit approvals, credit limits and monitoring procedures, and for certain transactions may utilize letters of credit, prepayments and guarantees.

For each of the years ended December 31, 2005, 2004 and 2003, Valero Energy Corp. accounted for 14%, 16% and 16% of our total consolidated revenues, respectively. No other single customer accounted for 10% or more of our total consolidated revenues for the years ended December 31, 2005, 2004 and 2003.

The carrying amount of cash and cash equivalents, accounts receivable, inventories, other current assets, accounts payable and accrued liabilities, other current liabilities and derivatives approximates their fair value due to their short-term nature.

Note 13. Unit-Based Compensation

1994 Long Term Incentive Plan

During 1994, the Company adopted the Texas Eastern Products Pipeline Company 1994 Long Term Incentive Plan ("1994 LTIP"). The 1994 LTIP provides certain key employees with an incentive award whereby a participant is granted an option to purchase Units. These same employees are also granted a stipulated number of Performance Units, the cash value of which may be used to pay for the exercise of the respective Unit options awarded Under the provisions of the 1994 LTIP, no more than one million options and two million Performance Units may be granted

When our calendar year earnings per unit (exclusive of certain special items) exceeds a stated threshold, each participant receives a credit to their respective Performance Unit account equal to the earnings per unit excess multiplied by the number of Performance Units awarded The balance in the Performance Unit account may be used to offset the cost of exercising Unit options granted in connection with the Performance Units or may be withdrawn two years after the underlying options expire, usually 10 years from the date of grant. Any unused balance previously credited is forfeited upon termination. We accrue compensation expense for the Performance Units awarded annually based upon the terms of the plan discussed above.

Under the agreement for such Unit options, the options become exercisable in equal installments over periods of one, two, and three years from the date of the grant. At December 31, 2005, all options have been fully exercised The Performance Unit account has a minimal liability balance which may be withdrawn by the participants after December 31, 2006.

A summary of Unit options granted under the terms of the 1994 LTIP is presented below:

	Options Outstanding	Options Exercisable	Exercise Range
Unit Options:			
Outstanding at December 31, 2002	90,091	90,091	$ 13.81 – $25.69
Exercised	(90,091)	(90,091)	$ 13.81 – $25.69
Outstanding at December 31, 2003	—	—	

We have not granted options for any periods presented. During the year ended December 31, 2003, all remaining outstanding Unit options were exercised. For options previously outstanding, we followed the intrinsic value method for recognizing stock-based compensation expense. The exercise price of all options awarded under the 1994 LTIP equaled the market price of our Units on the date of grant. Accordingly, we recognized no compensation expense at the date of grant. Had compensation expense been determined consistent with SFAS No 123, *Accounting for Stock-Based Compensation*, no compensation expense would have been recognized for the years ended December 31, 2005, 2004 and 2003.

1999 and 2002 Phantom Unit Plans

Effective September 1, 1999, the Company adopted the Texas Eastern Products Pipeline Company, LLC 1999 Phantom Unit Retention Plan ("1999 PURP") Effective June 1, 2002, the Company adopted the Texas Eastern Products Pipeline Company, LLC 2002 Phantom Unit Retention Plan ("2002 PURP"). The 1999 PURP and the 2002 PURP provide key employees with incentive awards whereby a participant is granted phantom units These phantom units are automatically redeemed for cash based on the vested portion of the fair market value of the phantom units at stated redemption dates. The fair market value of each phantom unit is equal to the closing price of a Unit as reported on the New York Stock Exchange on the redemption date.

Under the agreement for the phantom units, each participant will vest 10% of the number of phantom units initially granted under his or her award at the end of each of the first four years and will vest the final 60% at the end of the fifth year. Each participant is required to redeem their phantom units as they vest. They are also entitled to quarterly cash distributions equal to the product of the number of phantom units outstanding for the participant and the amount of the cash distribution that we paid per Unit to unitholders. We accrued compensation expense annually based upon the terms of the 1999 PURP and 2002 PURP discussed above. At December 31, 2004, we had an accrued liability balance of $1.6 million for compensation related to the 1999 PURP and 2002 PURP. Due to a change of ownership as a result of the sale of our General Partner on February 24, 2005 (see Note 1), all outstanding units under both the 1999 PURP and the 2002 PURP fully vested and were redeemed by participants. As such, there were no outstanding units at December 31, 2005 under either the 1999 PURP or the 2002 PURP.

2000 Long Term Incentive Plan

Effective January 1, 2000, the General Partner established the Texas Eastern Products Pipeline Company, LLC 2000 Long Term Incentive Plan ("2000 LTIP") to provide key employees incentives to achieve improvements in our financial performance. Generally, upon the close of a three-year performance period, if the participant is then still an employee of the General Partner, the participant will receive a cash payment in an amount equal to (1) the applicable performance percentage specified in the award multiplied by (2) the number of phantom units granted under the award multiplied by (3) the average of the closing prices of a Unit over the ten consecutive trading days immediately preceding the last day of the performance period. Generally, a participant's performance percentage is based upon the improvement of our Economic Value Added (as defined below) during a three-year performance period over the Economic Value Added during the three-year period immediately preceding the performance period. If a participant incurs a separation from service during the performance period due to death, disability or retirement (as such terms are defined in the 2000 LTIP), the participant will be entitled ~~to receive a cash payment in an amount equal to the amount computed as described above multiplied by a fraction, the numerator of which is the number of days that have~~ elapsed during the performance period prior to the participant's separation from service and the denominator of which is the number of days in the performance period. Due to a change of ownership as a result of the sale of our General Partner on February 24, 2005, all outstanding units under the 2000 LTIP for plan years 2003 and 2004 were fully vested and redeemed by participants. As such, there were no outstanding units at December 31, 2005, for awards granted for the plan years ended December 31, 2004 and 2003. At December 31, 2005, phantom units outstanding for awards granted for the plan year ended December 31, 2005, were 23,400.

Economic Value Added means our average annual EBITDA for the performance period minus the product of our average asset base and our cost of capital for the performance period. For purposes of the 2000 LTIP for plan years 2000 through 2002, EBITDA means our earnings before net interest expense, depreciation and amortization and our proportional interest in EBITDA of our joint ventures as presented in our consolidated financial statements prepared in accordance with generally accepted accounting principles, except that at his discretion the Chief Executive Officer ("CEO") of the Company may exclude gains or losses from extraordinary, unusual or non-recurring items. For the years ended December 31, 2005, 2004 and 2003, EBITDA means, in addition to the above definition of EBITDA, earnings before other income – net. Average asset base means the quarterly average, during the performance period, of our gross value of property, plant and equipment, *plus* products and crude oil operating oil supply and the gross value of intangibles and equity investments. Our cost of capital is approved by our CEO at the date of award grant.

In addition to the payment described above, during the performance period, the General Partner will pay to the participant the amount of cash distributions that we would have paid to our unitholders had the participant been the owner of the number of Units equal to the number of phantom units granted to the participant under this award. We accrue compensation expense annually based upon the terms of the 2000 LTIP discussed above. At December 31, 2005 and 2004, we had an accrued liability balance of $0.7 million and $2.4 million, respectively, for compensation related to the 2000 LTIP.

2005 Phantom Unit Plan

Effective January 1, 2005, the Company adopted the Texas Eastern Products Pipeline Company, LLC 2005 Phantom Unit Plan ("2005 PURP") to provide key employees incentives to achieve improvements in our financial performance. Generally, upon the close of a three-year performance period, if the participant is then still an employee of the General Partner, the participant will receive a cash payment in an amount equal to (1) the grantee's vested percentage multiplied by (2) the number of phantom units granted under the award multiplied by (3) the average of the closing prices of a Unit over the ten consecutive trading days immediately preceding the last day of the performance period. Generally, a participant's vested percentage is based upon the improvement of our EBITDA (as defined below) during a three-year performance period over the target EBITDA as defined at the beginning of each year during the three-year performance period. EBITDA means our earnings before minority interest, net interest expense, other income – net, income taxes, depreciation and amortization and our proportional interest in EBITDA of our joint ventures as presented in our consolidated financial statements

Notes To Consolidated Financial Statements—(Continued)

prepared in accordance with generally accepted accounting principles, except that at his discretion, our CEO may exclude gains or losses from extraordinary, unusual or non-recurring items. At December 31, 2005, phantom units outstanding for awards granted for the plan year ended December 31, 2005, were 53,600.

In addition to the payment described above, during the performance period, the General Partner will pay to the participant the amount of cash distributions that we would have paid to our unitholders had the participant been the owner of the number of Units equal to the number of phantom units granted to the participant under this award. We accrue compensation expense annually based upon the terms of the 2005 PURP discussed above. At December 31, 2005, we had an accrued liability balance of $0.7 million for compensation related to the 2005 PURP.

Note 14. Operating Leases

We use leased assets in several areas of our operations. Total rental expense for the years ended December 31, 2005, 2004 and 2003, was $24.0 million, $22.1 million and $18.8 million, respectively. The following table sets forth our minimum rental payments under our various operating leases for the years ending December 31 (in thousands):

2006	$19,536
2007	17,391
2008	10,863
2009	7,682
2010	6,645
Thereafter	21,544
	$83,661

Note 15. Employee Benefits

Retirement Plans

The TEPPCO Retirement Cash Balance Plan ("TEPPCO RCBP") was a non-contributory, trustee-administered pension plan. In addition, the TEPPCO Supplemental Benefit Plan ("TEPPCO SBP") was a non-contributory, nonqualified, defined benefit retirement plan, in which certain executive officers participated. The TEPPCO SBP was established to restore benefit reductions caused by the maximum benefit limitations that apply to qualified plans. The benefit formula for all eligible employees was a cash balance formula. Under a cash balance formula, a plan participant accumulated a retirement benefit based upon pay credits and current interest credits. The pay credits were based on a participant's salary, age and service. We used a December 31 measurement date for these plans.

On May 27, 2005, the TEPPCO RCBP and the TEPPCO SBP were amended. Effective May 31, 2005, participation in the TEPPCO RCBP was frozen, and no new participants were eligible to be covered by the plan after that date. Effective December 31, 2005, all plan benefits accrued were frozen, participants will not receive additional pay credits after that date, and all plan participants were 100% vested regardless of their years of service. The TEPPCO RCBP plan was terminated effective December 31, 2005, subject to IRS approval of plan termination, and plan participants will have the option to receive their benefits either through a lump sum payment in 2006 or through an annuity. For those plan participants who elect to receive an annuity, we will purchase an annuity contract from an insurance company in which the plan participant owns the annuity, absolving us of any future obligation to the participant. Participants in the TEPPCO SBP received pay credits through November 30, 2005, and received lump sum benefit payments in December 2005. Both the RCBP and SBP benefit payments are discussed below.

In June 2005, we recorded a curtailment charge of $0.1 million in accordance with SFAS No. 88, *Employers' Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits*, as a result of the TEPPCO RCBP and TEPPCO SBP amendments. As of May 31, 2005, the following assumptions were changed for purposes of determining the net periodic benefit costs for the remainder of 2005: the discount rate, the long-term rate of return on plan assets, and the assumed mortality table. The discount rate was decreased from 5.75% to 5.00% to reflect rates of returns on bonds currently available to settle the liability. The expected long-term rate of return on plan assets was changed from 8% to 2% due to the movement of plan funds from equity investments into short-term money market funds. The mortality table was changed to reflect overall improvements in mortality experienced by the general population. The curtailment charge arose due to the accelerated recognition of the unrecognized prior service costs. We recorded additional settlement charges of approximately $0.2 million in the fourth quarter of 2005 relating to the TEPPCO SBP. We expect to record additional settlement charges of approximately $4.0 million in 2006 relating to the TEPPCO RCBP for any existing unrecognized losses upon the plan termination and final distribution of the assets to the plan participants

Notes To Consolidated Financial Statements—(Continued)

The components of net pension benefits costs for the TEPPCO RCBP and the TEPPCO SBP for the years ended December 31, 2005, 2004 and 2003, were as follows (in thousands):

	Year Ended December 31,		
	2005	2004	2003
Service cost benefit earned during the year	$4,393	$ 3,653	$ 3,179
Interest cost on projected benefit obligation	934	719	504
Expected return on plan assets	(671)	(878)	(604)
Amortization of prior service cost	5	7	7
Recognized net actuarial loss	129	57	24
SFAS 88 curtailment charge	50	—	—
SFAS 88 settlement charge	194	—	—
Net pension benefits costs	$5,034	$ 3,558	$ 3,110

Other Postretirement Benefits

We provided certain health care and life insurance benefits for retired employees on a contributory and non-contributory basis ("TEPPCO OPB"). Employees became eligible for these benefits if they met certain age and service requirements at retirement, as defined in the plans. We provided a fixed dollar contribution, which did not increase from year to year, towards retired employee medical costs. The retiree paid all health care cost increases due to medical inflation. We used a December 31 measurement date for this plan.

In May 2005, benefits provided to employees under the TEPPCO OPB were changed. Employees eligible for these benefits received them through December 31, 2005, however, effective December 31, 2005, these benefits were terminated. As a result of this change in benefits and in accordance with SFAS No. 106, *Employers' Accounting for Postretirement Benefits Other Than Pensions*, we recorded a curtailment credit of approximately $1.7 million in our accumulated postretirement obligation which reduced our accumulated postretirement obligation to the total of the expected remaining 2005 payments under the TEPPCO OPB. The current employees participating in this plan were transferred to DEFS, who will continue to provide postretirement benefits to these retirees. We recorded a one-time settlement to DEFS in the third quarter of 2005 of $0.4 million for the remaining postretirement benefits.

The components of net postretirement benefits cost for the TEPPCO OPB for the years ended December 31, 2005, 2004 and 2003, were as follows (in thousands):

	Year Ended December 31,		
	2005	2004	2003
Service cost benefit earned during the year	$ 81	$ 165	$ 137
Interest cost on accumulated postretirement benefit obligation	69	153	137
Amortization of prior service cost	53	126	126
Recognized net actuarial loss	4	1	—
Curtailment credit	(1,676)	—	—
Settlement credit	(4)	—	—
Net postretirement benefits costs	$(1,473)	$ 445	$ 400

Effective June 1, 2005, the payroll functions performed by DEFS for our General Partner were transferred from DEFS to EPCO. For those employees who were receiving certain other postretirement benefits at the time of the acquisition of our General Partner by DFI, DEFS will continue to provide these benefits to those employees. Effective June 1, 2005, EPCO began providing certain other postretirement benefits to those employees who became eligible for the benefits after June 1, 2005, and will charge those benefit related costs to us. As a result of these changes, we recorded a $1.2 million reduction in our other postretirement obligation in June 2005.

We employed a building block approach in determining the long-term rate of return for plan assets. Historical markets were studied and long-term historical relationships between equities and fixed-income were preserved consistent with a widely accepted capital market principle that assets with higher volatility generate a greater return over the long run. Current market factors such as inflation and interest rates were evaluated before long-term capital market assumptions were determined. The long-term portfolio return was established via a building block approach with proper consideration of diversification and rebalancing. Peer data and historical returns were reviewed to check for reasonability and appropriateness.

Notes To Consolidated Financial Statements—(Continued)

The weighted average assumptions used to determine benefit obligations for the retirement plans and other postretirement benefit plans at December 31, 2005 and 2004, were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2005	2004	2005	2004
Discount rate	4.59%	5.75%	5.75%	5.75%
Increase in compensation levels	—	5.00%	—	—

The weighted average assumptions used to determine net periodic benefit cost for the retirement plans and other postretirement benefit plans for the years ended December 31, 2005 and 2004, were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2005	2004	2005	2004
Discount rate[(1)]	5.75%/5.00%	6.25%	5.75%/5.00%	6.25%
Increase in compensation levels	5.00%	5.00%	—	—
Expected long-term rate of return on plan assets[(2)]	8.00%/2.00%	8.00%	—	—

(1) Expense was remeasured on May 31, 2005, as a result of TEPPCO RCBP and TEPPCO SBP amendments. The discount rate was decreased from 5.75% to 5% effective June 1, 2005, to reflect rates of returns on bonds currently available to settle the liability.

(2) As a result of TEPPCO RCBP and TEPPCO SBP amendments, the expected return on assets was changed from 8% to 2% due to the movement of plan funds from equity investments into short-term money market funds, effective June 1, 2005.

The following table sets forth our pension and other postretirement benefits changes in benefit obligation, fair value of plan assets and funded status as of December 31, 2005 and 2004 (in thousands):

	Pension Benefits		Other Postretirement Benefits	
	2005	2004	2005	2004
Change in benefit obligation				
Benefit obligation at beginning of year	$15,940	$11,256	$ 2,964	$ 2,467
Service cost	4,393	3,653	81	165
Interest cost	934	719	70	153
Actuarial loss	2,740	572	76	205
Retiree contributions	—	—	64	60
Benefits paid	(910)	(260)	(80)	(86)
Impact of curtailment	(986)	—	(3,575)	—
Settlement	—	—	400	—
Benefit obligation at end of year	$22,111	$15,940	$ —	$ 2,964
Change in plan assets				
Fair value of plan assets at beginning of year	$14,969	$10,921	$ —	$ —
Actual return on plan assets	20	808	—	—
Retiree contributions	—	—	64	60
Employer contributions	9,025	3,500	16	26
Benefits paid	(910)	(260)	(80)	(86)
Fair value of plan assets at end of year	$23,104	$14,969	$ —	$ —
Reconciliation of funded status				
Funded status	$ 994	$ (971)	$ —	$(2,964)
Unrecognized prior service cost	—	33	—	1,003
Unrecognized actuarial loss	4,067	2,006	—	472
Net amount recognized	$ 5,061	$ 1,068	$ —	$(1,489)

We estimate the following benefit payments, which reflect expected future service, as appropriate, will be paid (in thousands):

	Pension Benefits	Other Postretirement Benefits
2006	$ 22,360	$ —

Plan Assets

We employed a total return investment approach whereby a mix of equities and fixed income investments were used to maximize the long-term return of plan assets for a prudent level of risk. Risk tolerance was established through careful consideration of plan liabilities, plan funded status and corporate financial condition. The investment portfolio contained a diversified blend of equity and fixed-income investments. Furthermore, equity investments were diversified across U.S. and non-U.S. stocks, both growth and value equity style, and small, mid and large capitalizations. Investment risk and return parameters were reviewed and evaluated periodically to ensure compliance with stated investment objectives and guidelines. This comprehensive review incorporated investment portfolio performance, annual liability measurements and periodic asset/liability studies.

The following table sets forth the weighted average asset allocations for the retirement plans and other postretirement benefit plans as of December 31, 2005 and 2004, by asset category (in thousands):

	December 31,	
Asset Category	2005	2004
Equity securities	—	63 %
Debt securities	—	35 %
Other (money market and cash)	100 %	2 %
Total	100 %	100 %

We do not expect to make further contributions to our retirement plans and other postretirement benefit plans in 2006.

Other Plans

DEFS also sponsored an employee savings plan, which covered substantially all employees. Effective February 24, 2005, in conjunction with the change in ownership of our General Partner, our participation in this plan ended. Plan contributions on behalf of the Company of $0.9 million, $3.5 million and $3.2 million were recognized for the period January 1, 2005 through February 23, 2005, and during the years ended December 31, 2004 and 2003, respectively.

Note 16. Commitments and Contingencies

Litigation

In the fall of 1999 and on December 1, 2000, the General Partner and the Partnership were named as defendants in two separate lawsuits in Jackson County Circuit Court, Jackson County, Indiana, styled *Ryan E. McCleery and Marcia S. McCleery, et al. v. Texas Eastern Corporation, et al.* (including the General Partner and Partnership) and *Gilbert Richards and Jean Richards v. Texas Eastern Corporation, et al.* (including the General Partner and Partnership). In both cases, the plaintiffs contend, among other things, that we and other defendants stored and disposed of toxic and hazardous substances and hazardous wastes in a manner that caused the materials to be released into the air, soil and water. They further contend that the release caused damages to the plaintiffs. In their complaints, the plaintiffs allege strict liability for both personal injury and property damage together with gross negligence, continuing nuisance, trespass, criminal mischief and loss of consortium. The plaintiffs are seeking compensatory, punitive and treble damages. On January 27, 2005, we entered into Release and Settlement Agreements with the McCleery plaintiffs and the Richards plaintiffs dismissing all of these plaintiffs' claims on terms that did not have a material adverse effect on our financial position, results of operations or cash flows. Although we did not settle with all plaintiffs and we therefore remain named parties in the *Ryan E. McCleery and Marcia S. McCleery, et al. v. Texas Eastern Corporation, et al.* action, a co-defendant has agreed to indemnify us for all remaining claims asserted against us. Consequently, we do not believe that the outcome of these remaining claims will have a material adverse effect on our financial position, results of operations or cash flows.

On December 21, 2001, TE Products was named as a defendant in a lawsuit in the 10th Judicial District, Natchitoches Parish, Louisiana, styled *Rebecca L. Grisham et al v. TE Products Pipeline Company, Limited Partnership*. In this case, the plaintiffs contend that our pipeline, which crosses the plaintiffs' property, leaked toxic products onto their property and, consequently caused damages to them. We have filed an answer to the plaintiffs' petition denying the allegations, and we are defending ourselves vigorously against the lawsuit. The plaintiffs have not stipulated the amount of damages they are seeking in the suit; however, this case is covered by insurance. We do not believe that the outcome of this lawsuit will have a material adverse effect on our financial position, results of operations or cash flows.

On April 2, 2003, Centennial was served with a petition in a matter styled *Adams, et al. v. Centennial Pipeline Company LLC, et al.* This matter involves approximately 2,000 plaintiffs who allege that over 200 defendants, including Centennial, generated, transported, and/or disposed of hazardous and toxic waste at two sites in Bayou Sorrell, Louisiana, an underground injection well and a landfill. The plaintiffs allege personal injuries, allergies, birth defects, cancer and death. The underground injection well has been in operation since May 1976. Based upon current information, Centennial appears to be a *de minimis* contributor, having used the disposal site during the two month time period of December 2001 to January 2002. Marathon has been handling this matter for Centennial under its operating agreement with Centennial. TE Products has a 50% ownership interest in Centennial. On November 30, 2004, the court approved a class settlement. The time period for parties to appeal this settlement expired in March 2005, and the class settlement became final. The terms of the settlement did not have a material adverse effect on our financial position, results of operations or cash flows.

In May 2003, the General Partner was named as a defendant in a lawsuit styled *John R. James, et al. v. J Graves Insulation Company, et al.* as filed in the first Judicial District Court, Caddo Parish, Louisiana. There are numerous plaintiffs identified in the action that are alleged to have suffered damages as a result of alleged exposure to asbestos-containing products and materials. According to the petition and as a result of a preliminary investigation, the General Partner believes that the only claim asserted against it results from one individual for the period from July 1971 through June 1972, who is alleged to have worked on a facility owned by the General Partner's predecessor. This period represents a small portion of the total alleged exposure period from January 1964 through December 2001 for this individual. The individual's claims involve numerous employers and alleged job sites. The General Partner has been unable to confirm involvement by the General Partner or its predecessors with the alleged location, and it is uncertain at this time whether this case is covered by insurance. Discovery is planned, and the General Partner intends to defend itself vigorously against this lawsuit. The plaintiffs have not stipulated the amount of damages that they are seeking in this suit. We are obligated to reimburse the General Partner for any costs it incurs related to this lawsuit. We cannot estimate the loss, if any, associated with this pending lawsuit. We do not believe that the outcome of this lawsuit will have a material adverse effect on our financial position, results of operations or cash flows.

On August 5, 2005, we were named as a third-party defendant in a matter styled *ConocoPhillips, et al. v. BP Amoco Seaway Products Pipeline Company* as filed in the 55th Judicial District of Harris County, Texas. ConocoPhillips alleges a right to indemnity from BP Amoco Seaway Products Pipeline Company ("BP Amoco") for tax liability incurred by ConocoPhillips as a result of the reverse merger of Seaway Pipeline Company (the "Original Seaway Partnership"). The reverse merger of the Original Seaway Partnership was undertaken in preparation for our purchase of ARCO Pipe Line Company pursuant to the Amended and Restated Purchase Agreement (the "Purchase Agreement") dated May 10, 2000, between us and Atlantic Richfield Company. BP Amoco has claimed a right to indemnity from us under the Purchase Agreement should BP Amoco have any indemnity liability to ConocoPhillips. ConocoPhillips alleges the income tax liability to be approximately $4.0 million. On January 20, 2006, we entered into a settlement agreement with BP Amoco dismissing and resolving all of BP Amoco's claims. The terms of the settlement did not have a material adverse effect on our financial position, results of operations or cash flows.

In 1991, we were named as a defendant in a matter styled *Jimmy R. Green, et al. v. Cities Service Refinery, et al.* as filed in the 26 th Judicial District Court of Bossier Parish, Louisiana. The plaintiffs in this matter reside or formerly resided on land that was once the site of a refinery owned by one of our co-defendants. The former refinery is located near our Bossier City facility. Plaintiffs have claimed personal injuries and property damage arising from alleged contamination of the refinery property. The plaintiffs have recently pursued certification as a class and have significantly increased their demand to approximately $175.0 million. This revised demand includes amounts for environmental restoration not previously claimed by the plaintiffs. We have never owned any interest in the refinery property made the basis of this action, and we do not believe that we contributed to any alleged contamination of this property. While we cannot predict the ultimate outcome, we do not believe that the outcome of this lawsuit will have a material adverse effect on our financial position, results of operations or cash flows.

In addition to the litigation discussed above, we have been, in the ordinary course of business, a defendant in various lawsuits and a party to various other legal proceedings, some of which are covered in whole or in part by insurance. We believe that the outcome of these lawsuits and other proceedings will not individually or in the aggregate have a future material adverse effect on our consolidated financial position, results of operations or cash flows.

Regulatory Matters

Our operations are subject to federal, state and local laws and regulations governing the discharge of materials into the environment and various safety matters. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, imposition of injunctions delaying or prohibiting certain activities and the need to perform investigatory and remedial activities. We believe our operations have been and are in material compliance with applicable environmental and safety laws and regulations, and that compliance with existing environmental laws and regulations are not expected to have a material adverse effect on our competitive position, financial positions, results of operations or cash flows. However, risks of significant costs and liabilities are inherent in pipeline operations, and we cannot assure that significant costs and liabilities will not be incurred. Moreover, it is possible that other developments, such as increasingly strict environmental and safety laws and regulations and enforcement policies thereunder, and claims

Notes To Consolidated Financial Statements—(Continued)

for damages to property or persons resulting from our operations, could result in substantial costs and liabilities to us. At December 31, 2005 and 2004, we have an accrued liability of $2.4 million and $5.0 million, respectively, related to sites requiring environmental remediation activities.

On March 26, 2004, a decision in *ARCO Products Co., et al. v. SFPP*, Docket OR96-2-000, was issued by the FERC, which made several significant determinations with respect to finding "changed circumstances" under the Energy Policy Act of 1992 ("EP Act"). The decision largely clarifies, but does not fully quantify, the standard required for a complainant to demonstrate that an oil pipeline's rates are no longer subject to the rate protection of the EP Act by demonstrating that a substantial change in circumstances has occurred since 1992 with respect to the basis of the rates being challenged. In the decision, the FERC found that a limited number of rate elements will significantly affect the economic basis for a pipeline company's rates. The elements identified in the decision are volume changes, allowed total return and total cost-of-service (including major cost elements such as rate base, tax rates and tax allowances, among others). The FERC did reject, however, the use of changes in tax rates and income tax allowances as stand-alone factors. Judicial review of that decision, which has been sought by a number of parties to the case, is currently pending before the U.S. Court of Appeals for the District of Columbia Circuit. We have not yet determined the impact, if any, that the decision, if it is ultimately upheld, would have on our rates if they were reviewed under the criteria of this decision.

On July 20, 2004, the District of Columbia Circuit issued an opinion in *BP West Coast Products LLC v. FERC*. In reviewing a series of orders involving SFPP, L.P., the court held among other things that the FERC had not adequately justified its policy of providing an oil pipeline limited partnership with an income tax allowance equal to the proportion of its income attributable to partnership interests owned by corporate partners. Under the FERC's initial ruling, SFPP, L.P. was permitted an income tax allowance on its cost-of-service filing for the percentage of its net operating (pre-tax) income attributable to partnership units held by corporations, and was denied an income tax allowance equal to the percentage attributable to partnership units held by non-corporate partners. The court remanded the case back to the FERC for further review. As a result of the court's remand, on May 4, 2005, the FERC issued its Policy Statement on Income Tax Allowances, which permits regulated partnerships, limited liability companies and other pass-through entities an income tax allowance on their income attributable to any owner that has an actual or potential income tax liability on that income, regardless whether the owner is an individual or corporation. If there is more than one level of pass-through entities, the regulated company income must be traced to where the ultimate tax liability lies. The Policy Statement is to be applied in individual cases, and the regulated entity bears the burden of proof to establish the tax status of its owners. On December 16, 2005, the FERC issued the first of those decisions, in an order involving SFPP (the "SFPP Order"). The SFPP Order confirmed that an MLP is entitled to a tax allowance with respect to partnership income for which there is an "actual or potential income tax liability" and determined that a unitholder that is required to file a Form 1040 or Form 1120 tax return that includes partnership income or loss is presumed to have an actual or potential income tax liability sufficient to support a tax allowance on that partnership income. The FERC also established certain other presumptions, including that corporate unitholders are presumed to be taxed at the maximum corporate tax rate of 35% while individual unitholders (and certain other types of unitholders taxed like individuals) are presumed to be taxed at a 28% tax rate. The SFPP Order remains subject to further administrative proceedings (including compliance filings by SFPP and possible rehearing requests), as well as potential judicial review. The ultimate outcome of the FERC's inquiry on income tax allowance should not affect our current rates and rate structure because our rates are not based on cost-of-service methodology. However, the outcome of the income tax allowance would become relevant to us should we (i) elect in the future to use cost-of-service to support our rates, or (ii) be required to use such methodology to defend our indexed rates.

In 1994, the Louisiana Department of Environmental Quality ("LDEQ") issued a compliance order for environmental contamination at our Arcadia, Louisiana, facility. In 1999, our Arcadia facility and adjacent terminals were directed by the Remediation Services Division of the LDEQ to pursue remediation of this contamination. Effective March 2004, we executed an access agreement with an adjacent industrial landowner who is located upgradient of the Arcadia facility. This agreement enables the landowner to proceed with remediation activities at our Arcadia facility for which it has accepted shared responsibility. At December 31, 2005, we have an accrued liability of $0.2 million for remediation costs at our Arcadia facility. We do not expect that the completion of the remediation program proposed to the LDEQ will have a future material adverse effect on our financial position, results of operations or cash flows.

On March 17, 2003, we experienced a release of 511 barrels of jet fuel from a storage tank at our Blue Island terminal located in Cook County, Illinois. As a result of the release, we have entered into an Agreed Order with the State of Illinois, which required us to conduct an environmental investigation. At this time, we have complied with the terms of the Agreed Order, and the results of the environmental investigation indicated there were no soil or groundwater impacts from the release. On August 30, 2005, a final settlement was reached with the State of Illinois. The settlement included the payment of a civil penalty of $0.1 million and the requirement that we make certain modifications to the equipment of the facility, none of which are expected to have a material adverse effect on our financial position, results of operations or cash flows.

On July 22, 2004, we experienced a release of approximately 12 barrels of jet fuel from a sump at our Lebanon, Ohio, terminal. The released jet fuel was contained within a storm water retention pond located on the terminal property. Six migratory waterfowl were affected by the jet fuel and were subsequently euthanized by or at the request of the United States Fish and Wildlife Service ("USFWS"). On October 1, 2004, the USFWS served us with a Notice of Violation, alleging that we violated 16 USC 703 of the Migratory Bird Treaty Act for the "take[ing] of migratory birds by illegal methods." On February 7, 2005, we entered into a Memorandum of Understanding with the USFWS, settling all aspects of this matter. The terms of this settlement did not have a material effect on our financial position, results of operations or cash flows.

On July 27, 2004, we received notice from the United States Department of Justice ("DOJ") of its intent to seek a civil penalty against us related to our November 21, 2001, release of approximately 2,575 barrels of jet fuel from our 14-inch diameter pipeline located in Orange County, Texas. The DOJ, at the request of the Environmental Protection Agency, is seeking a civil penalty against us for alleged violations of the Clean Water Act ("CWA") arising out of this release. We are in discussions with the DOJ regarding this matter and have responded to its request for additional information. The maximum statutory penalty proposed by the DOJ for this alleged violation of the CWA is $2.1 million. We do not expect any civil penalty to have a material adverse effect on our financial position, results of operations or cash flows.

On September 18, 2005, a propane release and fire occurred at our Todhunter facility, near Middletown, Ohio. The incident resulted in the death of one of our employees. There were no other injuries. On or about February 22, 2006, we received verbal notification from a representative of the Occupational Safety and Health Administration that they intend to serve us with a citation arising out of this incident. At this time, we have not received any citation, and we cannot predict with certainty the amount of any fine or penalty associated with any such citation; however, we do not expect any fine or penalty to have a material adverse effect on our financial position, results of operations or cash flows.

Rates of interstate petroleum products and crude oil pipeline companies, like us, are currently regulated by the FERC primarily through an index methodology, which allows a pipeline to change its rates based on the change from year to year in the Producer Price Index for finished goods ("PPI Index"). Effective as of February 24, 2003, FERC Order on Remand modified the PPI Index from PPI – 1% to PPI. On April 22, 2003, several shippers filed a petition in the United States Court of Appeals for the District of Columbia Circuit (the "Court"), *Flying J. Inc., Lion Oil Company, Sinclair Oil Corporation and Tesoro Refining and Marketing Company vs. Federal Energy Regulatory Commission*; Docket No. 03-1107, seeking a review of whether the FERC's adoption of the PPI Index was reasonable and supported by the evidence. On April 9, 2004, the Court handed down a decision denying the shippers' petition for review, stating the shippers failed to establish that any of the FERC's methodological choices (or combination of choices) were both erroneous and harmful.

As an alternative to using the PPI Index, interstate petroleum products and crude oil pipeline companies may elect to support rate filings by using a cost-of-service methodology, competitive market showings ("Market- Based Rates") or agreements between shippers and petroleum products and crude oil pipeline companies that the rate is acceptable.

Other

Centennial entered into credit facilities totaling $150.0 million, and as of December 31, 2005, $150.0 million was outstanding under those credit facilities. TE Products and Marathon have each guaranteed one-half of the repayment of Centennial's outstanding debt balance (plus interest) under a long-term credit agreement, which expires in 2024, and a short-term credit agreement, which expires in 2007. The guarantees arose in order for Centennial to obtain adequate financing, and the proceeds of the credit agreements were used to fund construction and conversion costs of its pipeline system. Prior to the expiration of the long-term credit agreement, TE Products could be relinquished from responsibility under the guarantee should Centennial meet certain financial tests. If Centennial defaults on its outstanding balance, the estimated maximum potential amount of future payments for TE Products and Marathon is $75.0 million each at December 31, 2005.

TE Products, Marathon and Centennial have entered into a limited cash call agreement, which allows each member to contribute cash in lieu of Centennial procuring separate insurance in the event of a third-party liability arising from a catastrophic event. There is an indefinite term for the agreement and each member is to contribute cash in proportion to its ownership interest, up to a maximum of $50.0 million each. As a result of the catastrophic event guarantee, TE Products has recorded a $4.6 million obligation, which represents the present value of the estimated amount that we would have to pay under the guarantee. If a catastrophic event were to occur and we were required to contribute cash to Centennial, contributions exceeding our deductible might be covered by our insurance.

One of our subsidiaries, TCO, has entered into master equipment lease agreements with finance companies for the use of various equipment. We have guaranteed the full and timely payment and performance of TCO's obligations under the agreements. Generally, events of default would trigger our performance under the guarantee. The maximum potential amount of future payments under the guarantee is not estimable, but would include base rental payments for both current and future equipment, stipulated loss payments in the event any equipment is stolen, damaged, or destroyed and any future indemnity payments We carry insurance coverage that may offset any payments required under the guarantees.

On February 24, 2005, the General Partner was acquired from DEFS by DFI The General Partner owns a 2% general partner interest in us and is the general partner of the Partnership. On March 11, 2005, the Bureau of Competition of the Federal Trade Commission ("FTC") delivered written notice to DFI's legal advisor that it was conducting a non-public investigation to determine whether DFI's acquisition of the General Partner may substantially lessen competition. The General Partner is cooperating fully with this investigation

Substantially all of the petroleum products that we transport and store are owned by our customers. At December 31, 2005, TCTM and TE Products had approximately 4.0 million barrels and 22.5 million barrels, respectively, of products in their custody that was owned by customers. We are obligated for the transportation, storage and delivery of such products on behalf of our customers. We maintain insurance adequate to cover product losses through circumstances beyond our control.

We carry insurance coverage consistent with the exposures associated with the nature and scope of our operations. Our current insurance coverage includes (1) commercial general liability insurance for liabilities to third parties for bodily injury and property damage resulting from our operations; (2) workers' compensation coverage to required statutory limits; (3) automobile liability insurance for all owned, non-owned and hired vehicles covering liabilities to third parties for bodily injury and property damage, and (4) property insurance covering the replacement value of all real and personal property damage, including damages arising from earthquake, flood damage and business interruption/extra expense. For select assets, we also carry pollution liability insurance that provides coverage for historical and gradual pollution events. All coverages are subject to certain deductibles, limits or sub-limits and policy terms and conditions.

We also maintain excess liability insurance coverage above the established primary limits for commercial general liability and automobile liability insurance. Limits, terms, conditions and deductibles are commensurate with the nature and scope of our operations. The cost of our general insurance coverages has increased over the past year reflecting the changing conditions of the insurance markets These insurance policies, except for the pollution liability policies, are through EPCO (see Note 7).

Note 17. Segment Information

We have three reporting segments:

- Our Downstream Segment, which is engaged in the transportation and storage of refined products, LPGs and petrochemicals;
- Our Upstream Segment, which is engaged in the gathering, transportation, marketing and storage of crude oil and distribution of lubrication oils and specialty chemicals; and
- Our Midstream Segment, which is engaged in the gathering of natural gas, fractionation of NGLs and transportation of NGLs.

The amounts indicated below as "Partnership and Other" relate primarily to intersegment eliminations and assets that we hold that have not been allocated to any of our reporting segments.

Our Downstream Segment revenues are earned from transportation and storage of refined products and LPGs, intrastate transportation of petrochemicals, sale of product inventory and other ancillary services. The two largest operating expense items of the Downstream Segment are labor and electric power. We generally realize higher revenues during the first and fourth quarters of each year since our operations are somewhat seasonal. Refined products volumes are generally higher during the second and third quarters because of greater demand for gasolines during the spring and summer driving seasons. LPGs volumes are generally higher from November through March due to higher demand for propane, a major fuel for residential heating. Our Downstream Segment also includes the results of operations of the northern portion of the Dean Pipeline, which transports, refinery grade propylene from Mont Belvieu to Point Comfort, Texas. Our Downstream Segment also includes our equity investments in Centennial and MB Storage (see Note 6).

Our Upstream Segment revenues are earned from gathering, transportation, marketing and storage of crude oil and distribution of lubrication oils and specialty chemicals, principally in Oklahoma, Texas, New Mexico and the Rocky Mountain region. Marketing operations consist primarily of aggregating purchased crude oil along our pipeline systems, or from third party pipeline systems, and arranging the necessary transportation logistics for the ultimate sale of the crude oil to local refineries, marketers or other end users. Our Upstream Segment also includes our equity investment in Seaway. Seaway consists of large diameter pipelines that transport crude oil from Seaway's marine terminals on the U.S. Gulf Coast to Cushing, Oklahoma, a crude oil distribution point for the central United States, and to refineries in the Texas City and Houston areas.

Our Midstream Segment revenues are earned from the fractionation of NGLs in Colorado, transportation of NGLs from two trunkline NGL pipelines in South Texas, two NGL pipelines in East Texas and a pipeline system (Chaparral) from West Texas and New Mexico to Mont Belvieu; the gathering of natural gas in the Green River Basin in southwestern Wyoming, through Jonah, and the gathering of CBM

Notes To Consolidated Financial Statements—(Continued)

and conventional natural gas in the San Juan Basin in New Mexico and Colorado, through Val Verde. On March 31, 2006, we sold our ownership interest in the Jonah Pioneer silica gel natural gas processing plant located near Opal, Wyoming to an affiliate of Enterprise for $38.0 million in cash (see Note 5 in the Notes to the Consolidated Financial Statements). Operating results of the Pioneer plant for the years ended December 31, 2005 and 2004 are shown as discontinued operations.

The tables below include financial information by reporting segment for the years ended December 31, 2005, 2004 and 2003 (in thousands):

	Year Ended December 31, 2005					
	Downstream Segment	Upstream Segment	Midstream Segment	Segments Total	Partnership and Other	Consolidated
Sales of petroleum products	$ —	$ 8,062,131	$ —	$ 8,062,131	$ (323)	$ 8,061,808
Operating revenues	287,191	48,108	211,171	546,470	(3,244)	543,226
Purchases of petroleum products	—	7,989,682	—	7,989,682	(3,244)	7,986,438
Operating expenses, including power	159,784	70,340	58,701	288,825	(323)	288,502
Depreciation and amortization expense	39,403	17,161	54,165	110,729	—	110,729
Gains on sales of assets	(139)	(118)	(411)	(668)	—	(668)
Operating income	88,143	33,174	98,716	220,033	—	220,033
Equity earnings (losses)	(2,984)	23,078	—	20,094	—	20,094
Other income, net	755	156	224	1,135	—	1,135
Earnings before interest from continuing operations	85,914	56,408	98,940	241,262	—	241,262
Discontinued operations	—	—	3,150	3,150	—	3,150
Earnings before interest	$ 85,914	$ 56,408	$ 102,090	$ 244,412	$ —	$ 244,412

	Year Ended December 31, 2004					
	Downstream Segment (as restated)	Upstream Segment (as restated)	Midstream Segment	Segments Total (as restated)	Partnership and Other	Consolidated (as restated)
Sales of petroleum products	$ —	$ 5,426,832	$ —	$ 5,426,832	$ —	$ 5,426,832
Operating revenues	279,400	49,163	195,902	524,465	(3,207)	521,258
Purchases of petroleum products	—	5,370,234	—	5,370,234	(3,207)	5,367,027
Operating expenses, including power	165,528	60,893	58,967	285,388	—	285,388
Depreciation and amortization expense	43,135	13,130	56,019	112,284	—	112,284
Gains on sales of assets	(526)	(527)		(1,053)	—	(1,053)
Operating income	71,263	32,265	80,916	184,444	—	184,444
Equity earnings (losses)	(6,544)	28,692	—	22,148	—	22,148
Other income, net	787	406	127	1,320	—	1,320
Earnings before interest from continuing operations	65,506	61,363	81,043	207,912	—	207,912
Discontinued operations	—	—	2,689	2,689	—	2,689
Earnings before interest	$ 65,506	$ 61,363	$ 83,732	$ 210,601	$ —	$ 210,601

Notes To Consolidated Financial Statements—(Continued)

	Year Ended December 31, 2003					
	Downstream Segment (as restated)	Upstream Segment (as restated)	Midstream Segment	Segments Total (as restated)	Partnership and Other	Consolidated (as restated)
Sales of petroleum products	$ —	$ 3,766,651	$ —	$ 3,766,651	$ —	$ 3,766,651
Operating revenues	266,427	39,564	185,105	491,096	(1,915)	489,181
Purchases of petroleum products	—	3,713,122	—	3,713,122	(1,915)	3,711,207
Operating expenses, including power	151,103	57,314	47,020	255,437	—	255,437
Depreciation and amortization expense	31,620	11,311	57,797	100,728	—	100,728
Gain on sale of assets	—	(3,948)		(3,948)	—	(3,948)
Operating income	83,704	28,416	80,288	192,408	—	192,408
Equity earnings (losses)	(7,384)	20,258	—	12,874	—	12,874
Other income, net	226	306	289	821	(73)	748
Earnings before interest	$ 76,546	$ 48,980	$ 80,577	$ 206,103	$ (73)	$ 206,030

The following table provides the total assets, capital expenditures and significant non-cash investing activities for each segment as of and for the years ended December 31, 2005, 2004 and 2003 (in thousands):

	Downstream Segment	Upstream Segment	Midstream Segment	Segments Total	Partnership and Other	Consolidated
December 31, 2005:						
Total assets	$ 1,056,217	$ 1,353,492	$ 1,280,548	$ 3,690,257	$ (9,719)	$ 3,680,538
Capital expenditures	58,609	40,954	119,837	219,400	1,153	220,553
Non-cash investing activities	1,429	—	—	1,429	—	1,429
December 31, 2004 (as restated):						
Total assets	$ 959,042	$ 1,069,007	$ 1,184,184	$ 3,212,233	$ (25,949)	$ 3,186,284
Capital expenditures	80,930	37,448	37,677	156,055	694	156,749
Capital expenditures for discontinued operations	—	—	7,398	7,398	—	7,398
December 31, 2003 (as restated):						
Total assets	$ 911,184	$ 833,723	$ 1,194,844	$ 2,939,751	$ (5,271)	$ 2,934,480
Capital expenditures	59,061	13,427	54,072	126,560	147	126,707
Capital expenditures for discontinued operations	—	—	13,810	13,810	—	13,810
Non-cash investing activities	61,042	—	—	61,042	—	61,042

The following table reconciles the segments total earnings before interest to consolidated net income for the three years ended December 31, 2005, 2004 and 2003 (in thousands):

	Years Ended December 31,		
	2005	2004 (as restated)	2003 (as restated)
Earnings before interest	$244,412	$ 210,601	$ 206,030
Interest expense—net	(81,861)	(72,053)	(84,250)
Net income	$162,551	$ 138,548	$ 121,780

Note 18. Comprehensive Income

SFAS No. 130, *Reporting Comprehensive Income* requires certain items such as foreign currency translation adjustments, minimum pension liability adjustments and unrealized gains and losses on certain investments to be reported in a financial statement. As of and for the year ended December 31, 2005, the components of comprehensive income were due to crude oil hedges. The crude oil hedges mature in December 2006. While the crude oil hedges are in effect, changes in the fair values of the crude oil hedges, to the extent the hedges are effective, are recognized in other comprehensive income until they are recognized in net income in future periods. As of and for the year ended December 31, 2004, the components of comprehensive income were due to the interest rate swap related to our variable rate revolving credit facility, which was designated as a cash flow hedge. The interest rate swap matured in April 2004. While the interest rate swap was in effect, changes in the fair value of the cash flow hedge, to the extent the hedge was effective, were recognized in other comprehensive income until the hedge interest costs were recognized in net income.

The accumulated balance of other comprehensive income related to our cash flow hedges is as follows (in thousands):

Balance at December 31, 2002 (as restated)	$(20,055)
Reclassification due to discontinued portion of cash flow hedge	989
Transferred to earnings	14,417
Change in fair value of cash flow hedge	1,747
Balance at December 31, 2003 (as restated)	$ (2,902)
Transferred to earnings	2,939
Change in fair value of cash flow hedge	(37)
Balance at December 31, 2004 (as restated)	$ —
Changes in fair values of crude oil cash flow hedges	11
Balance at December 31, 2005	$ 11

Note 19. Supplemental Condensed Consolidating Financial Information

Our significant operating subsidiaries, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P., Jonah Gas Gathering Company and Val Verde Gas Gathering Company, L.P., have issued unconditional guarantees of our debt securities. The guarantees are full, unconditional, and joint and several. TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P., Jonah Gas Gathering Company and Val Verde Gas Gathering Company, L.P. are collectively referred to as the "Guarantor Subsidiaries."

The following supplemental condensed consolidating financial information reflects our separate accounts, the combined accounts of the Guarantor Subsidiaries, the combined accounts of our other non-guarantor subsidiaries, the combined consolidating adjustments and eliminations and our consolidated accounts for the dates and periods indicated. For purposes of the following consolidating information, our investments in our subsidiaries and the Guarantor Subsidiaries' investments in their subsidiaries are accounted for under the equity method of accounting.

	December 31, 2005				
	TEPPCO Partners, L.P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
			(in thousands)		
Assets					
Current assets	$ 40,977	$ 107,692	$ 789,486	$ (39,026)	$ 899,129
Property, plant and equipment—net	—	1,335,724	624,344	—	1,960,068
Equity investments	1,201,388	461,741	202,343	(1,505,816)	359,656
Intercompany notes receivable	1,134,093	—	—	(1,134,093)	—
Intangible assets	—	345,005	31,903	—	376,908
Other assets	5,532	22,170	57,075	—	84,777
Total assets	$2,381,990	$ 2,272,332	$ 1,705,151	$ (2,678,935)	$ 3,680,538
Liabilities and partners' capital					
Current liabilities	$ 43,236	$ 140,743	$ 793,683	$ (40,451)	$ 937,211
Long-term debt	1,135,973	389,048	—	—	1,525,021
Intercompany notes payable	—	635,263	498,832	(1,134,095)	—
Other long term liabilities	1,422	14,564	950	—	16,936
Total partners' capital	1,201,359	1,092,714	411,686	(1,504,389)	1,201,370
Total liabilities and partners' capital	$2,381,990	$ 2,272,332	$ 1,705,151	$ (2,678,935)	$ 3,680,538

Notes To Consolidated Financial Statements—(Continued)

	December 31, 2004 (as restated)				
	TEPPCO Partners, L.P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
			(in thousands)		
Assets					
Current assets	$ 44,125	$ 85,992	$ 576,365	$ (62,928)	$ 643,554
Property, plant and equipment—net	—	1,211,312	492,390	—	1,703,702
Equity investments	1,011,131	420,343	202,326	(1,270,493)	363,307
Intercompany notes receivable	1,084,034	—	—	(1,084,034)	—
Intangible assets	—	372,621	34,737	—	407,358
Other assets	5,980	22,183	40,200	—	68,363
Total assets	$2,145,270	$ 2,112,451	$ 1,346,018	$ (2,417,455)	$ 3,186,284
Liabilities and partners' capital					
Current liabilities	$ 45,255	$ 142,513	$ 556,474	$ (62,930)	$ 681,312
Long-term debt	1,086,909	393,317	—	—	1,480,226
Intercompany notes payable	—	676,993	407,040	(1,084,033)	—
Other long term liabilities	2,003	9,980	1,660	—	13,643
Total partners' capital	1,011,103	889,648	380,844	(1,270,492)	1,011,103
Total liabilities and partners' capital	$2,145,270	$ 2,112,451	$ 1,346,018	$ (2,417,455)	$ 3,186,284

	Year Ended December 31, 2005				
	TEPPCO Partners, L.P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
			(in thousands)		
Operating revenues	$ —	$ 439,944	$ 8,168,657	$ (3,567)	$ 8,605,034
Costs and expenses	—	285,072	8,104,164	(3,567)	8,385,669
Gains on sales of assets	—	(551)	(117)	—	(668)
Operating income	—	155,423	64,610	—	220,033
Interest expense—net	—	(54,011)	(27,850)	—	(81,861)
Equity earnings	162,551	57,088	23,078	(222,623)	20,094
Other income—net	—	901	234	—	1,135
Income from continuing operations	162,551	159,401	60,072	(222,623)	159,401
Discontinued operations	—	3,150	—	—	3,150
Net income	$162,551	$ 162,551	$ 60,072	$ (222,623)	$ 162,551

	Year Ended December 31, 2004 (as restated)				
	TEPPCO Partners, L.P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
			(in thousands)		
Operating revenues	$ —	$ 420,060	$ 5,531,237	$ (3,207)	$ 5,948,090
Costs and expenses	—	294,155	5,473,751	(3,207)	5,764,699
Gains on sales of assets	—	(526)	(527)	—	(1,053)
Operating income	—	126,431	58,013	—	184,444
Interest expense—net	—	(48,902)	(23,151)	—	(72,053)
Equity earnings	138,548	57,454	28,692	(202,546)	22,148
Other income—net	—	876	444	—	1,320
Income from continuing operations	138,548	135,859	63,998	(202,546)	135,859
Discontinued operations	—	2,689	—	—	2,689
Net income	$138,548	$ 138,548	$ 63,998	$ (202,546)	$ 138,548

Notes To Consolidated Financial Statements—(Continued)

	Year Ended December 31, 2003 (as restated)				
	TEPPCO Partners, L.P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
			(in thousands)		
Operating revenues	$ —	$ 399,504	$ 3,858,243	$ (1,915)	$ 4,255,832
Costs and expenses	—	262,971	3,806,316	(1,915)	4,067,372
Gain on sale of assets	—	—	(3,948)	—	(3,948)
Operating income	—	136,533	55,875	—	192,408
Interest expense—net	—	(52,903)	(31,420)	73	(84,250)
Equity earnings	121,780	37,689	20,258	(166,853)	12,874
Other income—net	—	461	360	(73)	748
Net income	$121,780	$ 121,780	$ 45,073	$ (166,853)	$ 121,780

	Year Ended December 31, 2005				
	TEPPCO Partners, L.P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
			(in thousands)		
Cash flows from continuing operating activities					
Net income	$ 162,551	$ 162,551	$ 60,072	$ (222,623)	$ 162,551
Adjustments to reconcile net income to net cash provided by continuing operating activities:					
Income from discontinued operations	—	(3,150)	—	—	(3,150)
Depreciation and amortization	—	82,536	28,193	—	110,729
Earnings in equity investments, net of distributions	88,550	14,598	1,576	(87,733)	16,991
Gains on sales of assets	—	(551)	(117)	—	(668)
Changes in assets and liabilities and other	(54,540)	(57,645)	22,884	53,571	(35,730)
Net cash provided by continuing operating activities	196,561	198,339	112,608	(256,785)	250,723
Cash flows from discontinued operations	—	3,782	—	—	3,782
Net cash provided by operating activities	196,561	202,121	112,608	(256,785)	254,505
Cash flows from investing activities	(278,806)	(31,529)	(180,486)	139,906	(350,915)
Cash flows from financing activities	80,107	(184,126)	65,097	119,029	80,107
Net increase in cash and cash equivalents	(2,138)	(13,534)	(2,781)	2,150	(16,303)
Cash and cash equivalents at beginning of period	4,116	13,596	2,826	(4,116)	16,422
Cash and cash equivalents at end of period	$ 1,978	$ 62	$ 45	$ (1,966)	$ 119

Notes To Consolidated Financial Statements—(Continued)

	Year Ended December 31, 2004 (as restated)				
	TEPPCO Partners, L.P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
			(in thousands)		
Cash flows from continuing operating activities					
Net income	$ 138,548	$ 138,548	$ 63,998	$ (202,546)	$ 138,548
Adjustments to reconcile net income to net cash provided by continuing operating activities:					
Income from discontinued operations	—	(2,689)	—	—	(2,689)
Depreciation and amortization	—	89,438	22,846	—	112,284
Earnings in equity investments, net of distributions	94,509	(130)	8,208	(77,522)	25,065
Gains on sales of assets	—	(526)	(527)	—	(1,053)
Changes in assets and liabilities and other	(158,726)	29,707	(30,930)	151,690	(8,259)
Net cash provided by continuing operating activities	74,331	254,348	63,595	(128,378)	263,896
Cash flows from discontinued operations	—	3,271	—	—	3,271
Net cash provided by operating activities	74,331	257,619	63,595	(128,378)	267,167
Cash flows from continuing investing activities	98	(26,662)	(40,864)	(115,331)	(182,759)
Cash flows from discontinued investing activities	—	(7,398)	—	—	(7,398)
Cash flows from investing activities	98	(34,060)	(40,864)	(115,331)	(190,157)
Cash flows from financing activities	(90,057)	(229,206)	(25,575)	254,781	(90,057)
Net decrease in cash and cash equivalents	(15,628)	(5,647)	(2,844)	11,072	(13,047)
Cash and cash equivalents at beginning of period	19,744	19,243	5,670	(15,188)	29,469
Cash and cash equivalents at end of period	$ 4,116	$ 13,596	$ 2,826	$ (4,116)	$ 16,422

	Year Ended December 31, 2003 (as restated)				
	TEPPCO Partners, L.P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
			(in thousands)		
Cash flows from operating activities					
Net income	$ 121,780	$ 121,780	$ 45,073	$ (166,853)	$ 121,780
Adjustments to reconcile net income to net cash provided by operating activities:					
Depreciation and amortization	—	80,114	20,614	—	100,728
Earnings in equity investments, net of distributions	80,718	7,548	2,482	(75,619)	15,129
Gain on sale of assets	—	—	(3,948)	—	(3,948)
Changes in assets and liabilities and other	48,432	5,576	1,075	(46,348)	8,735
Net cash provided by operating activities	250,930	215,018	65,296	(288,820)	242,424
Cash flows from continuing investing activities	(175,568)	(164,872)	(37,589)	203,531	(174,498)
Cash flows from investing activities	—	(13,810)	—	—	(13,810)
Cash flows from discontinued investing activities	(175,568)	(178,682)	(37,589)	203,531	(188,308)
Cash flows from financing activities	(55,618)	(25,340)	(44,758)	70,101	(55,615)
Net increase (decrease) in cash and cash equivalents	19,744	10,996	(17,051)	(15,188)	(1,499)
Cash and cash equivalents at beginning of period	—	8,247	22,721	—	30,968
Cash and cash equivalents at end of period	$ 19,744	$ 19,243	$ 5,670	$ (15,188)	$ 29,469

Notes To Consolidated Financial Statements—(Continued)

Note 20. Restatement of Consolidated Financial Statements

We are restating our previously reported consolidated financial statements for the fiscal years ended December 31, 2003 and 2004. For the impact of the restated consolidated financial results for the quarterly periods during the years ended December 31, 2005 and 2004, see Note 21. We have determined that our method of accounting for the $33.4 million excess investment in Centennial, previously described as an intangible asset with an indefinite life, and the $27.1 million excess investment in Seaway, previously described as equity method goodwill, was incorrect. Through our accounting for these excess investments in Centennial and Seaway as intangible assets with indefinite lives and equity method goodwill, respectively, we have been testing the amounts for impairment on an annual basis as opposed to amortizing them over a determinable life. We determined that it would be more appropriate to account for these excess investments as intangible assets with determinable lives. As a result, we made non-cash adjustments that reduced the net value of the excess investments in Centennial and Seaway, and increased amortization expense allocated to our equity earnings. The effect of this restatement caused a $3.8 million and $4.0 million reduction to net income as previously reported for the fiscal years ended December 31, 2004 and 2003, respectively. As a result of the accounting correction, net income for the fiscal year ended December 31, 2005, includes a charge of $4.8 million, of which $3.8 million relates to the first nine months. Additionally, partners' capital at December 31, 2002, reflects a $2.5 million reduction representing the cumulative effect of this correction for fiscal years ended December 31, 2000 through 2002.

While we believe the impacts of these non-cash adjustments are not material to any previously issued financial statements, we determined that the cumulative adjustment for these non-cash items was too material to record in the fourth quarter of 2005, and therefore it was most appropriate to restate prior periods' results. These non-cash adjustments had no effect on our operating income, compensation expense, debt balances or ability to meet all requirements related to our debt facilities. The restatement had no impact on total cash flows from operating activities, investing activities or financing activities. All amounts in the accompanying consolidated financial statements have been adjusted for this restatement.

We will continue to amortize the $30.0 million excess investment in Centennial related to a contract using units-of-production methodology over a 10-year life. The remaining $3.4 million related to a pipeline will continue to be amortized on a straight-line basis over 35 years. We will continue to amortize the $27.1 million excess investment in Seaway on a straight-line basis over a 39-year life related primarily to a pipeline.

The following tables summarize the impact of the restatement adjustment on previously reported balance sheet amounts for the year ended December 31, 2004, and income statement amounts and cash flow amounts for the years ended December 31, 2004 and 2003 (in thousands):

Balance Sheet Amounts;

	December 31, 2004		
	As Previously Reported	Adjustment	As Restated
Equity investments	$ 373,652	$ (10,345)	$ 363,307
Total assets	$3,196,629	$ (10,345)	$3,186,284
Capital:			
General partner's interest	$ (33,006)	$ (2,875)	$ (35,881)
Limited partners' interest	1,054,454	(7,470)	1,046,984
Total partners' capital	1,021,448	(10,345)	1,011,103
Total liabilities and partners' capital	$3,196,629	$ (10,345)	$3,186,284

Notes To Consolidated Financial Statements—(Continued)

Income Statement Amounts:

	Years Ended December 31,	
	2004	2003
Equity earnings as previously reported	$ 25,981	$ 16,863
Adjustment for amortization of excess investments	(3,833)	(3,989)
Equity earnings as restated	$ 22,148	$ 12,874
Net income as previously reported	$142,381	$125,769
Adjustment for amortization of excess investments	(3,833)	(3,989)
Net income as restated	$138,548	$121,780
Net Income Allocation as previously reported:		
Limited Partner Unitholders	$101,307	$ 89,191
Class B Unitholder	—	1,806
General Partner	41,074	34,772
Total net income allocated	$142,381	$125,769
Basic and diluted net income per Limited Partner and Class B Unit as previously reported	$ 1.61	$ 1.52
Net Income Allocation as restated:		
Limited Partner Unitholders	$ 98,580	$ 86,357
Class B Unitholder	—	1,754
General Partner	39,968	33,669
Total net income allocated as restated	$138,548	$121,780
Basic and diluted net income per Limited Partner and Class B Unit as restated	$ 1.56	$ 1.47

Cash Flow Amounts:

	Year Ended December 31, 2004		
	As Previously Reported	Adjustment	As Restated
Cash flows from operating activities:			
Net income	$142,381	$ (3,833)	$138,548
Earnings in equity investments, net of distributions	21,232	3,833	25,065

	Year Ended December 31, 2003		
	As Previously Reported	Adjustment	As Restated
Cash flows from operating activities:			
Net income	$125,769	$ (3,989)	$121,780
Earnings in equity investments, net of distributions	11,140	3,989	15,129

Notes To Consolidated Financial Statements—(Continued)

Partners' Capital Amounts:

	Outstanding Limited Partner Units	General Partner's Interest	Limited Partners' Interests	Accumulated Other Comprehensive Loss	Total
2002:					
Partners' capital at December 31, 2002 as previously reported	53,809,597	$ 12,770	$ 899,127	$ (20,055)	$ 891,842
Restatement adjustment	—	(666)	(1,727)	—	(2,393)
Partners' capital at December 31, 2002 as restated (unaudited)	53,809,597	$ 12,104	$ 897,400	$ (20,055)	$ 889,449
2003:					
Partners' capital at December 31, 2003 as previously reported	62,998,554	$ (7,181)	$1,119,404	$ (2,902)	$1,109,321
Restatement adjustment	—	(1,769)	(4,743)	—	(6,512)
Partners' capital at December 31, 2003 as restated	62,998,554	$ (8,950)	$1,114,661	$ (2,902)	$1,102,809
2004:					
Partners' capital at December 31, 2004 as previously reported	62,998,554	$ (33,006)	$1,054,454	$ —	$1,021,448
Restatement adjustment	—	(2,875)	(7,470)	—	(10,345)
Partners' capital at December 31, 2004 as restated	62,998,554	$ (35,881)	$1,046,984	$ —	$1,011,103

Note 21. Quarterly Financial Information (Unaudited)

	First Quarter (as restated)	Second Quarter (as restated)	Third Quarter (as restated)	Fourth Quarter (as restated)
		(in thousands, except per Unit amounts)		
2005: (1)				
Operating revenues	$1,523,791	$ 2,087,385	$ 2,500,127	$ 2,493,731
Operating income	61,232	53,817	43,378	61,606
Income from continuing operations:				
As previously reported	$ 47,457	$ 41,387	$ 30,231	$ 44,137
Restatement adjustment	(1,152)	(1,311)	(1,348)	—
As restated	$ 46,305	$ 40,076	$ 28,883	$ 44,137
Income from discontinued operations	$ 1,124	$ 846	$ 692	$ 488
Net income:				
As previously reported	$ 48,581	$ 42,233	$ 30,923	$ 44,625
Restatement adjustment	(1,152)	(1,311)	(1,348)	—
As restated	$ 47,429	$ 40,922	$ 29,575	$ 44,625
Basic and diluted net income per Limited Partner Unit from continuing operations: (2)(3)				
As previously reported	$ 0.54	$ 0.44	$ 0.30	$ 0.45
Restatement adjustment	(0.01)	(0.02)	(0.01)	—
As restated	$ 0.53	$ 0.42	$ 0.29	$ 0.45
Basic and diluted net income per Limited Partner Unit from discontinued operations (3)	$ 0.01	$ 0.01	$ 0.01	$ —
Basic and diluted net income per Limited Partner Unit: (2)(3)				
As previously reported	$ 0.55	$ 0.45	$ 0.31	$ 0.45
Restatement adjustment	(0.01)	(0.02)	(0.01)	—
As restated	$ 0.54	$ 0.43	$ 0.30	$ 0.45

	First Quarter (as restated)	Second Quarter (as restated)	Third Quarter (as restated)	Fourth Quarter (as restated)
	(in thousands, except per Unit amounts)			
2004: (1)				
Operating revenues	$1,315,942	$ 1,352,107	$ 1,487,556	$ 1,792,485
Operating income	53,457	41,990	36,361	52,636
Income from continuing operations:				
As previously reported	$ 39,989	$ 37,348	$ 25,135	$ 37,220
Restatement adjustment	(713)	(1,129)	(1,085)	(906)
As restated	$ 39,276	$ 36,219	$ 24,050	$ 36,314
Income from discontinued operations	$ 444	$ 411	$ 720	$ 1,114
Net income:				
As previously reported	$ 40,433	$ 37,759	$ 25,855	$ 38,334
Restatement adjustment	(713)	(1,129)	(1,085)	(906)
As restated	$ 39,720	$ 36,630	$ 24,770	$ 37,428
Basic and diluted net income per Limited Partner Unit from continuing operations:				
As previously reported	$ 0.45	$ 0.43	$ 0.28	$ 0.42
Restatement adjustment	(0.01)	(0.02)	(0.01)	(0.01)
As restated	$ 0.44	$ 0.41	$ 0.27	$ 0.41
Basic and diluted net income per Limited Partner Unit from discontinued operations	$ 0.01	$ —	$ 0.01	$ 0.01
Basic and diluted net income per Limited Partner Unit:				
As previously reported	$ 0.46	$ 0.43	$ 0.29	$ 0.43
Restatement adjustment	(0.01)	(0.02)	(0.01)	(0.01)
As restated	$ 0.45	$ 0.41	$ 0.28	$ 0.42

(1) The quarterly financial information for 2004 and the first three quarters of 2005 reflect the impact of the restatement.

(2) The sum of the four quarters does not equal the total year due to rounding.

(3) Per Unit calculation includes 6,965,000 Units issued in May and June 2005.

Note 22. Subsequent Events

In January 2006, we entered into interest rate swaps with a total notional amount of $200.0 million, whereby we will receive a floating rate of interest and will pay a fixed rate of interest for a two-year term. These interest rate swaps were executed to decrease the exposure to potential increases in floating interest rates. Using the balances of outstanding debt at December 31, 2005, these interest rate swaps decrease the level of floating interest rate debt from 41% to 29% of total outstanding debt.

On February 13, 2006, we and an affiliate of Enterprise entered into a letter agreement related to an additional expansion (the "Jonah Expansion") of the Jonah system (the "Letter Agreement"). The Jonah Expansion will consist of the installation of approximately 90,000 horsepower of gas turbine compression at a new compression station, related new piping and certain related facilities, which is expected to increase capacity of the Jonah system from 1.5 billion cubic feet per day to 2.0 billion cubic feet per day. We expect to enter into a joint venture ("Joint Venture") agreement with Enterprise relating to the construction and financing of the Jonah Expansion. Enterprise will be responsible for all activities relating to the construction of the Jonah Expansion and will advance all amounts necessary to plan, engineer, construct or complete the Jonah Expansion (anticipated to be approximately $200.0 million). Such advance will constitute a subscription for an equity interest in the proposed Joint Venture (the "Subscription"). We expect the Jonah Expansion to be put into service in late 2006. We have the option to return to Enterprise up to 100% of the amount of the Subscription. If we return a portion of the Subscription to Enterprise, our relative interests in the proposed Joint Venture will be adjusted accordingly. The proposed Joint Venture will terminate without liability to either party if we return 100% of the Subscription.

Notes To Consolidated Financial Statements—(Continued)

Part IV, Exhibits and Financial Statement Schedule, Exhibit No. 12

COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES

The ratio of earnings to fixed charges is calculated using the Securities and Exchange Commission guidelines(a)

	Year Ended December 31,				
	2005	2004	2003	2002	2001
	(dollars in millions)				
Earnings as defined for fixed charges calculation					
Add:					
Pretax income (loss) from continuing operations (b)(e)	$2,951	$ 891	$ (839)	405	943
Fixed charges	847	1,115	1,245	1,219	846
Distributed income of equity investees	473	140	263	369	156
Deduct:					
Preference security dividend requirements of consolidated subsidiaries	27	32	102	157	165
Interest capitalized(c)	15	14	46	161	112
Total earnings (as defined for the Fixed Charges calculation)	$4,229	$2,100	$ 521	$1,675	$1,668
Fixed charges:					
Interest on debt, including capitalized portions	$ 796	$1,057	$1,116	$1,041	$ 659
Estimate of interest within rental expense	24	26	27	21	22
Preference security dividend requirements of consolidated subsidiaries	27	32	102	157	165
Total fixed charges	$ 847	$1,115	$1,245	$1,219	$ 846
Ratio of earnings to fixed charges(e)	5.0	1.9	(d)	1.4	2.0

(a) Income Statement amounts have been adjusted for discontinued operations.

(b) Excludes minority interest expenses and income or loss from equity investees.

(c) Excludes equity costs related to Allowance for Funds Used During Construction that are included in Other Income and Expenses in the Consolidated Statements of Operations.

(d) Earnings were inadequate to cover fixed charges by $724 million for the year ended December 31, 2003.

(e) Includes pre-tax gains on the sale of TEPPCO GP and LP of approximately $0.9 billion, net of minority interest, in 2005.

EXHIBIT INDEX

Exhibits filed herewith are designated by an asterisk (*). All exhibits not so designated are incorporated by reference to a prior filing, as indicated. Items constituting management contracts or compensatory plans or arrangements are designated by a double asterisk (**). Portions of the exhibit designated by a triple asterisk (***) have been omitted and filed separately with the Securities and Exchange Commission pursuant to a request for confidential treatment pursuant to Rule 24b-2 under the Securities and Exchange Act of 1934.

Exhibit Number	
2.1	Agreement and Plan of Merger, dated as of May 8, 2005, as amended as of July 11, 2005, as of October 3, 2005 and as of March 30, 2006, by and among the registrant, Duke Energy Corporation, Cinergy Corp., Deer Acquisition Corp., and Cougar Acquisition Corp. (filed with Form 8-K of Duke Energy Corporation, File No. 1-32853, April 4, 2006, as Exhibit 2-1).
~~2.2~~	~~Amended and Restated Combination Agreement dated as of September 20, 2001, among Duke Energy Corporation, 3058368 Nova Scotia Company,~~ 3946509 Canada Inc. and Westcoast Energy Inc. (filed with Form 10-Q of Duke Energy Carolinas, LLC for the quarter ended September 30, 2001, File No. 1-4928, as Exhibit 10-7)
2.3	Separation and Distribution Agreement, dated s of December 13, 2006, by and between Duke Energy Corporation and Spectra Energy Corp (filed with the Form 8-K of Duke Energy Corporation, File No. 1-32853, December 15, 2006, as Exhibit 2.1).
3.1	Amended and restated Certificate of Incorporation (filed with the Form 8-K of Duke Energy Corporation, File No. 1-32853, April 4, 2006, as Exhibit 3-1).
3.2	Amended and Restated By-Laws of registrant (filed with the Form 8-K of Duke Energy Corporation, File No. 1-32853, April 4, 2006, as Exhibit 3.2).
4	Rights Agreement, dated as of December 17, 1998, between the registrant and The Bank of New York, as Rights Agent (filed with the Form 8-K of Duke Energy Carolinas, LLC, dated February 11, 1999, File No. 1-4928, as Exhibit 4-1).
4.1	Amendment No. 1, dated as of May 8, 2005, to the Rights Agreement, dated as of December 17, 1998, between the registrant and The Bank of New York, as rights agent (filed with the Form 8-K of Duke Energy Carolinas, LLC, May 12, 2005, File No. 1-4928, as Exhibit 4-1).
10.1	Purchase and Sale Agreement dated as of February 24, 2005, by and between Enterprise GP Holdings LP and Duke Energy Field Services, LLC (filed with Form 10-K of Duke Energy Carolinas, LLC for the year ended December 31, 2004, File No. 1-4928, as Exhibit 10-25).
10.2	Term Sheet Regarding the Restructuring of Duke Energy Field Services LLC dated as of February 23, 2005, between Duke Energy Corporation and ConocoPhillips (filed with Form 10-K of Duke Energy Carolinas, LLC for the year ended December 31, 2004, File No. 1-4928, as Exhibit 10-26).
10.3	Reorganization Agreement by and among ConocoPhillips, Duke Capital LLC and Duke Energy Field Services, LLC dated as of May 26, 2005 (filed with Form 10-Q of Duke Energy Carolinas, LLC for the quarter ended June 30, 2005, File No. 1-4928, as Exhibit 10-4).
10.3.1	First Amendment to Reorganization Agreement by and among ConocoPhillips, Duke Capital LLC and Duke Energy Field Services, LLC dated as of June 30, 2005 (filed with Form 10-Q of Duke Energy Carolinas, LLC for the quarter ended June 30, 2005, File No. 1-4928, as Exhibit 10-4.1).
10.3.2	Second Amendment to Reorganization Agreement by and among ConocoPhillips, Duke Capital LLC and Duke Energy Field Services, LLC dated as of July 11, 2005 (filed with Form 10-Q of Duke Energy Carolinas, LLC for the quarter ended June 30, 2005, File No. 1-4928, as Exhibit 10-4.2)
10.4	Purchase and Sale Agreement dated as of January 8, 2006, by and among Duke Energy Americas, LLC, and LSP Bay II Harbor Holding, LLC (filed with the Form 10-Q of the registrant for the quarter ended March 31, 2006, File No. 1-32853, as Exhibit 10.2)

Exhibit Number	
10.4.1	Amendment to Purchase and Sale Agreement, dated as of May 4, 2006, by and among Duke Energy Americas, LLC, LS Power Generation, LLC (formerly known as LSP Bay II Harbor Holding, LLC), LSP Gen Finance Co, LLC, LSP South Bay Holdings, LLC, LSP Oakland Holdings, LLC, and LSP Morro Bay Holdings, LLC ((filed with the Form 10-Q of the registrant for the quarter ended March 31, 2006, File No. 1-32853, as Exhibit 10.2.1)
10.5	Second Amended and Restated Limited Liability Company Agreement of Duke Energy Field Services, LLC by and between ConocoPhillips Gas Company and Duke Energy Enterprises Corporation, dated as of July 5, 2005 (filed with the Form 10-K of Duke Energy Carolinas, LLC for the year ended December 31, 2005, File No. 1-4928, as Exhibit 10.5).
10.6	Limited Liability Company Agreement of Gulfstream Management & Operating Services, LLC dated as of February 1, 2001 between Duke Energy Gas Transmission Corporation and Williams Gas Pipeline Company (filed with Form 10-K of Duke Energy Carolinas, LLC for the year ended December 31, 2002, File No.1-4928, as Exhibit 10-18).
10.7	Formation Agreement between PanEnergy Trading and Market Services, Inc. and Mobil Natural Gas, Inc. dated May 29, 1996 (filed with Form 10-Q of PanEnergy Corp for the quarter ended June 30, 1996, File No. 1-8157, as Exhibit 2).
10.8***	Master Transaction Agreement by and among Duke Energy Marketing America, LLC, Duke Energy North America, LLC, Duke Energy Trading and Marketing, L.L.C., Duke Energy Marketing Limited Partnership, Engage Energy Canada, L.P. and Barclay Bank PLC, dated as of November 17, 2005 (filed with the Form 10-K of Duke Energy Carolinas, LLC for the year ended December 31, 2005, File No. 1-4928, as Exhibit 10.8).
10.9	$800,000,000 364-Day Credit Agreement dated as of June 29, 2005, among Duke Capital LLC, the banks listed therein, JPMorgan Chase Bank, N.A., as Administrative Agent, and Barclays Bank, PLC, as Syndication Agent (filed with Form 10-Q of Duke Energy Carolinas, LLC for the quarter ended June 30, 2005, File No. 1-4928, as Exhibit 10-3).
10.10	$600,000,000 Amended and Restated Credit Agreement dated as of June 30, 2005, among Duke Capital LLC, the banks listed therein, JPMorgan Chase Bank, N.A., as Administrative Agent, and Wachovia Bank, National Association, as Syndication Agent (filed with Form 10-Q of Duke Energy Carolinas, LLCfor the quarter ended June 30, 2005, File No. 1-4928, as Exhibit 10-2).
10.11	$500,000,000 Amended and Restated Credit Agreement dated as of June 30, 2005, among the registrant, the banks listed therein, Citibank N.A., as Administrative Agent, and Bank of America, N.A., as Syndication Agent (filed with Form 10-Q of Duke Energy Carolinas, LLCfor the quarter ended June 30, 2005, File No. 1-4928, as Exhibit 10-1).
10.12	Loan Agreement dated as of February 25, 2005 between Duke Energy Field Services, LLC and Duke Capital LLC (filed with Form 10-Q of Duke Energy Carolinas, LLCfor the quarter ended March 31, 2005, File No. 1-4928, as Exhibit 10-3).
10.13	Accelerated Share Acquisition Plan, dated March 18, 2005, between registrant and Merrill Lynch International (filed with Form 10-Q of Duke Energy Carolinas, LLCfor the quarter ended March 31, 2005, File No. 1-4928, as Exhibit 10-4).
10.14**	Directors' Charitable Giving Program (filed with Form 10-K of Duke Energy Carolinas, LLCfor the year ended December 31, 1992, File No. 1-4928, as Exhibit 10-P).
10.14.1**	Amendment to Directors' Charitable Giving Program dated June 18, 1997 (filed with Form 10-K of Duke Energy Carolinas, LLCfor the year ended December 31, 2003, File No. 1-4928, as Exhibit 10-1.1).
10.14.2**	Amendment to Directors' Charitable Giving Program dated July 28, 1997 (filed with Form 10-K of Duke Energy Carolinas, LLC for the year ended December 31, 2003, File No. 1-4928, as Exhibit 10-1.2)
10.14.3**	Amendment to Directors' Charitable Giving Program dated February 18, 1998 (filed with Form 10-K of Duke Energy Carolinas, LLCfor the year ended December 31, 2003, File No. 1-4928, as Exhibit 10-1.3)
10.15**	Duke Energy Corporation 1998 Long-Term Incentive Plan, as amended (filed as Exhibit 1 to Schedule 14A of Duke Energy Carolinas, LLC, March 28, 2003, File No. 1-4928).
10.16**	Duke Energy Corporation Executive Short-Term Incentive Plan (filed as Exhibit 2 to Schedule 14A of Duke Energy Carolinas, LLC, March 28, 2003, File No. 1-4928).

Exhibit Number	
10.17**	Duke Energy Corporation Executive Savings Plan, as amended and restated (filed with Form 10-K of Duke Energy Carolinas, LLCfor the year ended December 31, 2003, File No. 1-4928, as Exhibit 10-6).
10.17.1**	Amendment No. 1 to the Duke Energy Corporation Executive Savings Plan, dated October 27, 2004, effective December 31, 2004 (filed with Form 10-K of Duke Energy Carolinas, LLCfor the year ended December 31, 2004, File No. 1-4928, as Exhibit 10-6.1).
*10.17.2**	Amendment to the Duke Energy Corporation Executive Savings Plan, effective December 18, 2006.
*10.17.3**	Amendment to the Duke Energy Corporation Executive Savings Plan I & II, effective December 19, 2006
10.18**	Duke Energy Corporation Executive Cash Balance Plan (filed with Form 10-K of TEPPCO Partners, LP, File No. 1-10403, for the year ended December 31, 1999, as Exhibit 10-8).
10.18.1**	Amendment No. 1 to the Duke Energy Corporation Executive Cash Balance Plan, dated August 26, 1999 (filed with Form 10-K of Duke Energy Carolinas, LLCfor the year ended December 31, 2004, File No. 1-4928, as Exhibit 10-7.1).
10.18.2**	Amendment No. 2 to the Duke Energy Corporation Executive Cash Balance Plan, dated March 6, 2000 (filed with Form 10-K of Duke Energy Carolinas, LLCfor the year ended December 31, 2004, File No. 1-4928, as Exhibit 10-7.2).
10.18.3**	Amendment No. 3 to the Duke Energy Corporation Executive Cash Balance Plan, dated December 21, 2000 (filed with Form 10-K of Duke Energy Carolinas, LLCfor the year ended December 31, 2004, File No. 1-4928, as Exhibit 10-7.3).
10.18.4**	Amendment No. 4 to the Duke Energy Corporation Executive Cash Balance Plan, dated October 27, 2004, effective December 31, 2004 (filed with Form 10-K of Duke Energy Carolinas, LLCfor the year ended December 31, 2004, File No. 1-4928, as Exhibit 10-7.4).
*10.18.5**	Amendment to the Duke Energy Corporation Executive Cash Balance Plan, effective December 1, 2006.
*10.18.6**	Amendment to the Duke Energy Corporation Executive Cash Balance Plan I & II, effective December 31, 2006.
10.19**	Duke Energy Corporation Retirement Benefit Equalization Plan (filed with Form 10-K of TEPPCO Partners, LP, File No. 1-10403, for the year ended December 31, 1999, as Exhibit 10.9).
*10.19.1	Amendment to the Duke Energy Corporation Retirement Benefit Equalization Plan, effective December 21, 2006.
10.20**	Form of Key Employee Severance Agreement and Release between Duke Energy Corporation and certain key executives (filed with Form 10-K of Duke Energy Carolinas, LLCfor the year ended December 31, 1999, File No. 1-4928, as Exhibit 10-BB).
10.21**	Form of Change in Control Agreement between Duke Energy Corporation and certain key executives (filed with Form 10-K of Duke Energy Carolinas, LLCfor the year ended December 31, 1999, File No. 1-4928, as Exhibit 10-CC).
10.22**	Form of Change in Control Agreement between Duke Energy Corporation and certain key executives dated as of July 1, 2005 (filed with Form 8-K of Duke Energy Carolinas, LLC dated August 24, 2005, File No. 1-4928, as Exhibit 10-1).
10.23**	Employment Agreement dated November 2003 between Paul M. Anderson and Duke Energy Corporation (filed with Form 10-K of Duke Energy Carolinas, LLCfor the year ended December 31, 2003, File No. 1-4928, as Exhibit 10-18).
10.23.1**	First Amendment to Employment Agreement dated March 9, 2004 between Paul M. Anderson and Duke Energy Corporation (filed with Form 10-K of Duke Energy Carolinas, LLCfor the year ended December 31, 2003, File No. 1-4928, as Exhibit 10-18.1).
10.23.2**	Performance Award Agreement dated November 17, 2003, pursuant to Duke Energy Corporation 1998 Long-Term Incentive Plan, by and between Duke Energy Corporation and Paul M. Anderson (filed with Form 10-K of Duke Energy Carolinas, LLCfor the year ended December 31, 2004, File No. 1-4928, as Exhibit 10-18.2).

Exhibit Number	
10.23.3**	Phantom Stock Agreement dated November 17, 2003, pursuant to Duke Energy Corporation 1998 Long-Term Incentive Plan, by and between Duke Energy Corporation and Paul M. Anderson (filed with Form 10-K of Duke Energy Carolinas, LLCfor the year ended December 31, 2004, File No. 1-4928, as Exhibit 10-18.3).
10.23.4**	Non-Qualified Option Agreement dated as of November 17, 2003 pursuant to Duke Energy Corporation 1998 Long-Term Incentive Plan, by and between Duke Energy Corporation and Paul M. Anderson (filed with Form 10-K of Duke Energy Carolinas, LLCfor the year ended December 31, 2004, File No. 1-4928, as Exhibit 10-18.4).
10.23.5**	Second Amendment to Employment Agreement, dated as of April 4, 2006, by and among Paul M. Anderson, Duke Energy Holding Corp. (subsequently renamed Duke Energy Corporation) and Duke Energy Corporation (subsequently renamed Duke Energy Carolinas, LLC) (filed with Form 8-K of Duke Energy Corporation, File No. 1-32853, April 6, 2006, as Exhibit 10.5).
10.24**	Supplemental Compensation Agreement dated June 17, 1997 between Duke Power Company and Dr. Ruth G. Shaw (filed with Form 10-K of Duke Energy Carolinas, LLCfor the year ended December 31, 2003, File No. 1-4928, as Exhibit 10-19).
10.24.1**	Severance and Retention Agreement between Duke Energy Corporation and Ruth Shaw, dated April 4, 2006 (filed with Form 8-K of Duke Energy Corporation, File No. 1-32853, April 6, 2006, as Exhibit 10.7).
10.24.2**	Severance and Consulting Agreement between Duke Energy Corporation and Ruth Shaw, dated October 24, 2006 (filed with Form 8-K of Duke Energy Corporation, File No. 1-32853, October 27, 2006, as Exhibit 10.2).
10.25**	Resolution of Board of Directors, February 22, 2005, Approving Award of Phantom Stock to Nonemployee Directors (filed with Form 10-Q of Duke Energy Carolinas, LLCfor the quarter ended March 31, 2005, File No. 1-4928, as Exhibit 10-9).
10.26**	Resolution of Board of Directors, May 12, 2005, Approving Change to Retainer and Attendance Fees for Non-Employee Directors (filed with Form 10-Q of Duke Energy Carolinas, LLCfor the quarter ended June 30, 2005, File No. 1-4928, as Exhibit 10-5).
10.27**	Form of Performance Award Agreement dated February 28, 2005, pursuant to Duke Energy Corporation 1998 Long-Term Incentive Plan by and between Duke Energy Corporation and each of Fred J. Fowler, David L. Hauser, Jimmy W. Mogg and Ruth G. Shaw (filed with the Form 8-K of Duke Energy Carolinas, LLC, File No. 1-4928, February 28, 2006, as Exhibit 10-1).
10.28**	Form of Phantom Stock Award Agreement dated February 28, 2005, pursuant to Duke Energy Corporation 1998 Long-Term Incentive Plan by and between Duke Energy Corporation and each of Fred J. Fowler, David L. Hauser, Jimmy W. Mogg and Ruth G. Shaw (filed with the Form 8-K of Duke Energy Carolinas, LLC, File No. 1-4928, February 28, 2005, as Exhibit 10-2).
10.29**	Form of Phantom Stock Award Agreement dated as of May 11, 2005, pursuant to Duke Energy Corporation 1998 Long-Term Incentive Plan by and between Duke Energy Corporation and Jimmy W. Mogg. (filed with Form 10-Q of Duke Energy Carolinas, LLC for the quarter ended June 30, 2005, File No. 1-4928, as Exhibit 10-6).
10.30**	Form of Phantom Stock Award Agreement dated as of May 12, 2005, pursuant to Duke Energy Corporation 1998 Long-Term Incentive Plan by and between Duke Energy Corporation and nonemployee directors (filed in Form 8-K of Duke Energy Carolinas, LLC, May 17, 2005, File No. 1-4928, as Exhibit 10-1).
10.31**	Agreement between Duke Energy Corporation and Jimmy W. Mogg relating to certain retirement benefits, consisting of letter agreements dated May 25, 1995, August 4, 2001 and March 29, 2004 (filed with Form 10-K of Duke Energy Carolinas, LLCfor the year ended December 31, 2004, File No. 1-4928, as Exhibit 10-23).
10.32**	First Amendment to Key Employee Severance Agreement and General Release between Duke Energy Corporation and Richard J. Osborne, dated August 21, 2004 (filed with Form 10-Q of Duke Energy Carolinas, LLCfor the quarter ended October 31, 2004, File No. 1-4928, as Exhibit 10-2).

Exhibit Number	
10.33**	Certification of Chairman and Chief Executive Officer 2004 Performance Goals (filed in Form 8-K of Duke Energy Carolinas, LLC, February 28, 2005, File No. 1-4928, as item 1 of Item 1.01).
10.34**	Approval of Payment of 2004 Executive Officer Short-Term Incentives (filed in Form 8-K of Duke Energy Carolinas, LLC, February 28, 2005, File No. 1-4928, as item 2 of Item 1.01).
10.35**	Establishment of Chairman and Chief Executive Officer 2005 Performance Goals (filed in Form 8-K of Duke Energy Carolinas, LLC, February 28, 2005, File No. 1-4928, as item 3 of Item 1.01).
10.35.1**	Certification of Chairman and Chief Executive Officer 2005 Performance Goals (filed with Form 8-K of Duke Energy Carolinas, LLC, File No. 1-4928, March 3, 2006, as item 1 of Item 1.01).
10.36**	Establishment of Financial Measure Portion of Chairman and Chief Executive Officer 2006 Performance Goals (filed in Form 8-K of Duke Energy Carolinas, LLC, December 22, 2005, File No. 1-4928, as item 2 of Item 1.01).
10.37**	2005 Executive Officer Base Salaries, Short-Term Incentive Opportunities and Long-Term Incentive Opportunities (filed in Form 8-K of Duke Energy Carolinas, LLC, February 28, 2005, File No. 1-4928, as item 4 of Item 1.01).
~~10.38**~~	~~2006 Executive Officer Base Salaries and Short-Term Incentive Opportunities (filed in Form 8-K of Duke Energy Carolinas, LLC, December 22, 2005, File~~ No. 1-4928, as item 1 of Item 1.01).
10.38.1**	Final Approval of 2006 Executive Officer Financial Performance Target for Short-Term Incentive Opportunity (filed with Form 8-K of Duke Energy Carolinas, LLC, File No. 1-4928, March 3, 2006, as item 3 of Item 1.01).
10.39	Approval of Payment of 2005 Executive Officer Short-Term Incentives (filed with Form 8-K of Duke Energy Carolinas, LLC, File No. 1-4928, March 3, 2006, as item 2 of Item 1.01).
10.40	Form of Phantom Stock Award Agreement (filed with Form 8-K of Duke Energy Corporation, File No. 1-32853, April 4, 2006, as Exhibit 10.1).
10.41	Form of Performance Share Award Agreement (filed with Form 8-K of Duke Energy Corporation, File No. 1-32853, April 4, 2006, as Exhibit 10.2).
10.42**	Employment Agreement between Duke Energy Corporation and James E. Rogers, dated April 4, 2006 (filed with Form 8-K of Duke Energy Corporation, File No. 1-32853, April 6, 2006, as Exhibit 10.1).
10.42.1**	Performance Award Agreement between Duke Energy Corporation and James E. Rogers, dated April 4, 2006 (filed with Form 8-K of Duke Energy Corporation, File No. 1-32853, April 6, 2006, as Exhibit 10.2).
10.42.2**	Phantom Stock Grant Agreement between Duke Energy Corporation and James E. Rogers, dated April 4, 2006 (filed with Form 8-K of Duke Energy Corporation, File No. 1-32853, April 6, 2006, as Exhibit 10.3).
10.42.3**	Stock Option Grant Agreement between Duke Energy Corporation and James E. Rogers, dated April 4, 2006 (filed with Form 8-K of Duke Energy Corporation, File No. 1-32853, April 6, 2006, as Exhibit 10.4).
10.43**	Retention Award Agreement between Duke Energy Corporation and David L. Hauser, dated April 4, 2006 (filed with Form 8-K of Duke Energy Corporation, File No. 1-32853, April 6, 2006, as Exhibit 10.6).
10.44**	Summary of Director Compensation (filed with the Form 10-Q of Duke Energy Corporation for the quarter ended June 30, 2006, File No. 1-32853, as Exhibit 10.13).
10.45**	Form Phantom Stock Award Agreement and Election to Defer (filed with Form 8-K of Duke Energy Corporation, File No. 1-32853, May 16, 2006, as Exhibit 10.1).
10.46	Agreements with Piedmont Electric Membership Corporation, Rutherford Electric Membership Corporation and Blue Ridge Electric Membership Corporation to provide wholesale electricity and related power scheduling services from September 1, 2006 through December 31, 2021 (filed with the Form 10-Q of Duke Energy Corporation for the quarter ended June 30, 2006, File No. 1-32853, as Exhibit 10.15).

Exhibit Number	
10.47	Agreement with Dynegy Inc. and Rockingham Power, L.L.C. to acquire an approximately 825 megawatt power plant located in Rockingham County, N.C. for approximately $195 million (filed with Form 8-K of Duke Energy Corporation, File No. 1-32853, May 25, 2006, as Exhibit 10.1).
10.48	Purchase and Sale Agreement by and among Cinergy Capital & Trading, Inc., as Seller, and Fortis Bank, S.A./N.V., as Buyer, dated as of June 26, 2006 (filed with Form 8-K of Duke Energy Corporation, File No. 1-32853, June 30, 2006, as Exhibit 10.1)
10.49	Amended and Restated Credit Agreement, dated June 29, 2006, among Cinergy Corp., CG&E, PSI, ULH&P, The Banks Listed Herein, Barclays Bank PLC, as Administrative Agent, and JPMorgan Chase Bank, N.A., as Syndication Agent (filed with the Form 10-Q of Duke Energy Corporation for the quarter ended June 30, 2006, File No. 1-32853, as Exhibit 10.18).
10.50	Amended and Restated Credit Agreement, dated June 29, 2006, among Duke Capital LLC, The Banks Listed Herein, JPMorgan Chase Bank, N.A., as Administrative Agent, and Wachovia Bank, National Association, as Syndication Agent (filed with the Form 10-Q of Duke Energy Corporation for the quarter ended June 30, 2006, File No. 1-32853, as Exhibit 10.19).
10.51	Amended and Restated Credit Agreement, dated June 29, 2006, among Duke Energy Carolinas, LLC, The Banks Listed Herein, Citibank N.A., as Administrative Agent, and Banc of America, N.A., as Syndication Agent (filed with the Form 10-Q of Duke Energy Corporation for the quarter ended June 30, 2006, File No. 1-32853, as Exhibit 10.20).
10.52**	Form of Amendment to Performance Award Agreement and Phantom Stock Award Agreement (filed with Form 8-K of Duke Energy Corporation, File No. 1-32853, August 24, 2006, as Exhibit 10.1).
10.53**	Form of Amendment to Phantom Stock Award Agreement (filed with Form 8-K of Duke Energy Corporation, File No. 1-32853, August 24, 2006, as Exhibit 10.2).
10.54	Formation and Sale Agreement by and among Duke Ventures, LLC, Crescent Resources, LLC, Morgan Stanley Real Estate Fund V U.S. L.P., Morgan Stanley Real Estate Fund V Special U.S., L.P., Morgan Stanley Real Estate Investors V U.S., L.P., MSP Real Estate Fund V, L.P., and Morgan Stanley Strategic Investments, Inc., dated as of September 7, 2006 (filed with the Form 10-Q of Duke Energy Corporation for the quarter ended September 30, 2006, File No. 1-32853, as Exhibit 10.3).
10.55	Amendment No. 1 to Credit Agreement ("Amendment") dated as of February 28, 2006, by and among Duke Energy Carolinas, LLC (formerly known as Duke Energy Corporation), the banks listed therein, Citibank N.A., as Administrative Agent, and Bank of America, N.A., as Syndication Agent (filed with Form 8-K of Duke Energy Carolinas, LLC, File No. 1-4928, March 30, 2006, as Exhibit 10.1).
10.56	Fifteenth Supplemental Indenture, dated as of April 3, 2006, among the registrant, Duke Energy and JPMorgan Chase Bank, N.A. (as successor to Guaranty Trust Company of New York), as trustee (the "Trustee"), supplementing the Senior Indenture, dated as of September 1, 1998, between Duke Energy Carolinas, LLC (formerly Duke Energy Corporation) and the Trustee (filed with the Form 10-Q of Duke Energy Corporation for the quarter ended June 30, 2006, File No. 1-32853, as Exhibit 10.1).
10.57	Amendment No. 1 to the Twelfth Supplemental Indenture, dated as of April 1, 2006 ("Amendment No. 1"), among the registrant, Duke Energy and the Trustee, which amends the Twelfth Supplemental Indenture, dated as of May 7, 2003, between the registrant and the Trustee, pursuant to which the Convertible Notes were issued (filed with the Form 10-Q of Duke Energy Corporation for the quarter ended June 30, 2006, File No. 1-32853, as Exhibit 10.3).
10.58**	Duke Energy Corporation 2006 Long-Term Incentive Plan (filed with Form 8-K of Duke Energy Corporation, File No. 1-32853, October 27, 2006, as Exhibit 10.1).
10.59	Tax Matters Agreement, dated as of December 13, 2006, by and between Duke Energy Corporation and Spectra Energy Corp (filed with Form 8-K of Duke Energy Corporation, File No. 1-32853, December 15, 2006, as Exhibit 10.1).
10.60	Transition Services Agreement, dated as of December 13, 2006, by and between Duke Energy Corporation and Spectra Energy Corp (filed with Form 8-K of Duke Energy Corporation, File No. 1-32853, December 15, 2006, as Exhibit 10.2).

Exhibit Number	
10.61	Employee Matters Agreement, dated as of December 13, 2006, by and between Duke Energy Corporation and Spectra Energy Corp (filed with Form 8-K of Duke Energy Corporation, File No. 1-32853, December 15, 2006, as Exhibit 10.3).
10.62**	Agreement between Duke Energy Corporation and Fred J. Fowler, dated December 19, 2006 (filed with Form 8-K of Duke Energy Corporation, File No. 1-32853, December 22, 2006, as Exhibit 10.1).
*10.63**	Amendment to the Duke Energy Corporation Directors' Savings Plan I & II, effective December 19, 2006.
*10.64**	Amendment to the Cinergy Corp. Excess Pension Plan, effective January 1, 2007.
*10.65**	Amendment to the Cinergy Corp. 401(k) Excess Plan, effective December 18, 2006.
*10.66**	Amendment to the Cinergy Corp. Excess Profit Sharing Plan, effective December 19, 2006.
*10.67**	Amendment to the Cinergy Corp. 401(k) Excess Plan, effective December 19, 2006.
*10.68**	Amendment to the Cinergy Corp. Directors' Deferred Compensation Plan, effective December 19, 2006.
*12	Computation of Ratio of Earnings to Fixed Charges.
*21	List of Subsidiaries.
*23.1	Consent of Independent Registered Public Accounting Firm.
*23.2	Consent of Independent Registered Public Accounting Firm
*24.1	Power of attorney authorizing David L. Hauser and others to sign the annual report on behalf of the registrant and certain of its directors and officers.
*24.2	Certified copy of resolution of the Board of Directors of the registrant authorizing power of attorney.
*31.1	Certification of the Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*31.2	Certification of the Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*32.1	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*32.2	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

The total amount of securities of the registrant or its subsidiaries authorized under any instrument with respect to long-term debt not filed as an exhibit does not exceed 10% of the total assets of the registrant and its subsidiaries on a consolidated basis. The registrant agrees, upon request of the Securities and Exchange Commission, to furnish copies of any or all of such instruments to it.

Exhibit 10.17.2

AMENDMENT TO

DUKE ENERGY CORPORATION EXECUTIVE SAVINGS PLAN

The Duke Energy Corporation Executive Savings Plan (the "Plan") is amended, effective as of December 18, 2006, as follows:

1. Article II of the Duke Energy Corporation Executive Savings Plan I is hereby amended by adding a new subsection 2.30 at the end thereof as follows:

   "2.30 "Duke Energy Retirement Cash Balance Plan" means the Duke Energy Retirement Cash Balance Plan as in effect on October 3, 2004, without giving effect to amendments adopted thereafter."

2. Article II of the Duke Energy Corporation Executive Savings Plan is hereby amended by deleting the reference to the "Duke Energy Corporation 1998 Long-Term Incentive Plan" and substituting therefore the "Duke Energy Corporation 2006 Long-Term Incentive Plan".

3. Section 4.3 of the Duke Energy Corporation Executive Savings Plan II is hereby superseded and replaced in its entirety as set forth below:

"4.3 *Long-Term Incentive Plan Award Deferrals*. Each eligible Participant may irrevocably elect to defer, in accordance with the terms of this Plan, the entire amount of any nonvested Award granted under a long-term incentive plan maintained by the Company (including the Company's 2006 Long-Term Incentive Plan), subject to the following conditions:

(1) Except as otherwise provided in this Section, the deferral election shall be made by, and shall become irrevocable as of, December 31 (or such earlier date as specified by the Company) of the calendar year next preceding the calendar year for which such Award is granted, or at such later time as is permitted by the Company, consistent with Section 409A of the Code, during the calendar year in which a Participant initially becomes eligible for the Plan

(2) To the extent permitted by the Company, and except as otherwise provided in Section 4.3(3), with respect to an Award that is subject to a forfeiture condition requiring the Participant's continued services for a period of at least thirteen (13) months from the date that the service provider obtains a "legally binding right" to such Award (within the meaning of Section 409A of the Code), the deferral election shall be made by, and shall become irrevocable as of, the thirtieth (30th) day following the date that the Participant obtains the legally binding right to such Award.

(3) To the extent permitted by the Company, with respect to an Award that constitutes "performance-based compensation" (within the meaning of Section 409A of the Code), the deferral election shall be made by, and shall become irrevocable as of, the date that is 6 months before the end of the applicable performance period (or such earlier date as specified by the Company), provided that in no event may such deferral election be made after such Award has become both substantially certain to be paid and readily ascertainable (within the meaning of Section 409A of the Code).

(4) Upon the date that an Award that the Participant has elected to defer would otherwise have been payable, the number of shares of stock or the cash payment that would have become so payable but for the deferral election shall be converted into an equal number of units in the Duke Energy Common Stock—Stock Deferrals Subaccount.

(5) Dividend Equivalents, to the extent deferred, shall also be deferred and credited to the Participant's Duke Energy Common Stock—Stock Deferrals Subaccount commencing on the payment date of the first cash dividend of Duke Energy Common Stock that is declared after the date on which the deferred Award vests.

(6) No deferral of a stock option or restricted stock award shall be permissible."

4. Section 4.4 of the Duke Energy Corporation Executive Savings Plan II is hereby superseded and replaced in its entirety as set forth below:

"4.4 *Dividend Equivalents Deferrals.* Each eligible Participant may irrevocably elect to defer, in accordance with the terms of this Plan, 100% of the amounts that would otherwise become payable as Dividend Equivalents, with respect to (i) an Award that is designated in the Award Agreement as a "Chairman's Award," or (ii) an Award with respect to which the Award Agreement specifically provides for the deferral of Dividend Equivalents. Such election must be made by the Participant at the time the Participant elects to defer receipt of the related Award pursuant to the terms of Section 4.3. Dividend Equivalents that have been deferred pursuant to the first sentence of this Section and credited to the Participant's Account shall be credited to the Participant's Duke Energy Common Stock—Stock Deferrals Subaccount as of the dates such amounts would otherwise become payable pursuant to such award."

5. Section 4.5 of the Duke Energy Corporation Executive Savings Plan II is hereby amended by replacing the words "Eligible Pay" with the words "Eligible Earnings" and by replacing the words "Before Tax Savings" with the words "Before-Tax Elective Deferrals".

6. The last sentence of Section 7.1 of the Duke Energy Corporation Executive Savings Plan II is hereby deleted in its entirety.

7. Except as explicitly set forth herein, the Plan will remain in full force and effect.
This amendment has been approved and signed by an authorized officer of Duke Energy Corporation as of the date specified above.

DUKE ENERGY CORPORATION

By: /s/ CHRISTOPHER C. ROLFE
Christopher C. Rolfe
Group Executive and Chief
Administrative Officer

AMENDMENT TO

DUKE ENERGY CORPORATION EXECUTIVE SAVINGS PLAN I & II

(as Amended and Restated effective January 1, 2003)

The Duke Energy Corporation Executive Savings Plan I & II (as Amended and Restated effective January 1, 2003) (the "Plan") is amended, effective as of December 19, 2006, as follows:

1. Article VI of the Plan is hereby amended by adding the following new Section 6 8 at the end thereof:

"6 8 *Adjustments to Duke Energy Common Stock—Stock Deferrals Subaccount and Duke Energy Common Stock Fund.* Each phantom unit of Duke Energy Corporation common stock credited to the Duke Energy Common Stock—Stock Deferrals Subaccount and Duke Energy Common Stock Fund on behalf of a Participant on the Distribution Date shall be converted, as of the Distribution Date, into phantom units of Spectra Energy Corp common stock and phantom units of Duke Energy Corporation common stock and reallocated as follows:

(a) The number of phantom units of Spectra Energy Corp common stock shall be equal to the number of shares of Spectra Energy Corp common stock to which the Participant would have been entitled on the Distribution had the phantom units of Duke Energy Corporation common stock represented actual shares of Duke Energy Corporation as of the Record Date, the resulting number of phantom units of Spectra Energy Corp common stock being rounded down to the nearest whole unit.

(b) The resulting number of phantom units of Spectra Energy Corp common stock shall automatically be transferred from the Duke Energy Common Stock—Stock Deferrals Subaccount and Duke Energy Common Stock Fund and credited to the RSP Investment Option that invests primarily in Spectra Energy Corp common stock (the "Spectra Common Stock Fund"), effective as of the Distribution Date.

(c) A Participant may elect, pursuant to rules and procedures prescribed by the Company, to reallocate amounts deemed invested in the Spectra Common Stock Fund into any other open investment option. The Spectra Common Stock Fund shall be closed to additional deferrals and to transfers from any other investment option.

(d) Capitalized terms used in this Section 6.8 that are not defined in this Plan shall have the meaning set forth in the Employee Matters Agreement by and between Duke Energy Corporation and Spectra Energy Corp "

2. Article XIV of the Plan is hereby amended by adding the following new Section 14 5 at the end thereof:

"14.5 *Transfer of Accounts.* The Account of each Spectra Energy Participant maintained under the Plan immediately prior to the Distribution Date shall be transferred to the Spectra Energy Corp Executive Savings Plan and assumed by Spectra Energy Corp as of the Distribution Date (the "Assumed Amounts"). For purposes of this Plan, the term "Assumed Amounts" shall include any amounts of Base Pay or Incentive Plan awards of a Spectra Energy Participant that are earned but not yet paid as of the Distribution Date or equity awards granted to a Spectra Energy Participant under the Duke Energy Corporation 1998 Long-Term Incentive Plan, that were properly deferred by the Spectra Energy Participant under the Plan but that had not yet been credited to his or her Account under the Plan as of the Distribution Date. Each such Spectra Energy Participant shall have no further rights under the Plan immediately after his or her Account is transferred to the Spectra Energy Corp Executive Savings Plan and assumed by Spectra Energy Corp in accordance with the terms and conditions of the Employee Matters Agreement by and between Duke Energy Corporation and Spectra Energy Corp (the "Employee Matters Agreement") Capitalized terms used in this Section 14 5 that are not defined in this Plan shall have the meaning set forth in the Employee Matters Agreement "

3 Except as explicitly set forth herein, the Plan will remain in full force and effect.

This amendment has been executed by an authorized officer of Duke Energy Corporation on December 19, 2006.

DUKE ENERGY CORPORATION

By: /s/ CHRISTOPHER C. ROLFE
Christopher C. Rolfe
Group Executive and
Chief Administrative Officer

Exhibit 10.18.5

AMENDMENT TO

DUKE ENERGY CORPORATION

EXECUTIVE CASH BALANCE PLAN

The Duke Energy Corporation Executive Cash Balance Plan (the "Plan") is amended, effective as of December 1, 2006, as follows:

1. Section 2.16 of the Duke Energy Corporation Executive Cash Balance Plan I is hereby superseded and replaced in its entirety as set forth below:

   "2.16 "Retirement Cash Balance Plan" means the Duke Energy Retirement Cash Balance Plan as in effect on October 3, 2004, without giving effect to amendments adopted thereafter."

2. The last sentence of Section 4.4 of the Duke Energy Corporation Executive Cash Balance Plan II is hereby deleted in its entirety.

3. The first two sentences of Section 6.1 of the Duke Energy Corporation Executive Cash Balance Plan II are hereby deleted and replaced in their entirety with the following:

   "A Participant whose Company employment terminates on or after December 31, 2006 will receive, or will begin to receive, payment of his vested Make Whole Account and his vested Supplemental Account, if any, as soon as administratively feasible following the month in which the Participant's employment terminates."

4. Except as explicitly set forth herein, the Plan will remain in full force and effect.

This amendment has been approved and signed by an authorized officer of Duke Energy Corporation as of the date specified above.

DUKE ENERGY CORPORATION

By: /s/ CHRISTOPHER C. ROLFE
Christopher C. Rolfe
Group Executive and Chief
Administrative Officer

Exhibit 10.18.6

AMENDMENT TO

DUKE ENERGY CORPORATION EXECUTIVE CASH BALANCE PLAN I & II

(As Amended and Restated effective January 1, 1999)

The Duke Energy Corporation Executive Cash Balance Plan I & II (As Amended and Restated effective January 1, 1999) (the "Plan") is amended, effective as of December 31, 2006, as follows:

1. Article 12 of the Plan is hereby amended by adding the following new Section 12.5 at the end thereof:

   "12.5 *Transfer of Accounts*. The Make-Whole Account and Supplemental Account, if any, of each Spectra Energy Participant maintained under the Plan immediately prior to the Distribution Date shall be transferred to the Spectra Energy Corp Executive Cash Balance Plan and assumed by Spectra Energy Corp as of the Distribution Date. Each such Spectra Energy Participant shall have no further rights under the Plan immediately after his or her Make-Whole Account and Supplemental Account, if any, are transferred to the Spectra Energy Corp Executive Cash Balance Plan and assumed by Spectra Energy Corp in accordance with the terms and conditions of the Employee Matters Agreement by and between Duke Energy Corporation and Spectra Energy Corp (the "Employee Matters Agreement"). Capitalized terms used in this Section 12.5 that are not defined in this Plan shall have the meaning set forth in the Employee Matters Agreement."

2. Except as explicitly set forth herein, the Plan will remain in full force and effect.

This amendment has been executed by an authorized officer of Duke Energy Corporation on December 19, 2006.

DUKE ENERGY CORPORATION

By: /s/ CHRISTOPHER C. ROLFE
Christopher C. Rolfe
Group Executive and
Chief Administrative Officer

Exhibit 10.19.1

AMENDMENT TO

DUKE ENERGY CORPORATION RETIREMENT BENEFIT EQUALIZATION PLAN

(effective January 1, 1999)

The Duke Energy Corporation Retirement Benefit Equalization Plan (effective January 1, 1999) (the "Plan") is amended, effective as of December 21, 2006, as follows:

1. The Plan is hereby amended by adding the following new Section 13 at the end thereof:

"13. *Termination of Plan*. Effective as of December 31, 2006, the Plan is hereby frozen such that no further benefits or entitlements shall accrue thereunder."

This amendment has been approved and signed by an authorized officer of Duke Energy Corporation as of the date specified above.

DUKE ENERGY CORPORATION

By: /s/ CHRISTOPHER C. ROLFE
Christopher C. Rolfe
Group Executive and
Chief Administrative Officer

Exhibit 10.63

AMENDMENT TO

DUKE ENERGY CORPORATION DIRECTORS' SAVINGS PLAN I & II

(as Amended and Restated effective February 24, 2004)

The Duke Energy Corporation Directors' Savings Plan I & II (as Amended and Restated effective February 24, 2004) (the "Plan") is amended, effective as of December 19, 2006, as follows:

1. Article IV of the Plan is hereby amended by adding the following new Section 4 5 at the end thereof:

"4.5 Each phantom unit of Company common stock credited to the DECS Investment Option and the Stock Deferral Investment Option on behalf of a Participant on the Distribution Date shall be converted, as of the Distribution Date, into phantom units of Company common stock and phantom units of Spectra Energy Corp common stock and reallocated as follows:

(i) The number of phantom units of Spectra Energy Corp common stock shall be equal to the number of shares of Spectra Energy Corp common stock to which the Participant would have been entitled on the Distribution had the phantom units of Company common stock represented actual shares of the Company as of the Record Date, the resulting number of phantom units of Spectra Energy Corp common stock being rounded down to the nearest whole unit.

(ii) The resulting number of phantom units of Spectra Energy Corp common stock shall automatically be transferred from the DECS Investment Option and the Stock Deferral Investment Option and credited to the Plan's investment option that corresponds to the RSP's Spectra Energy Corp Common Stock Fund (the "SECS Investment Option")

(iii) A Participant (or, if the Participant is dead. the Participant's beneficiary) may elect, pursuant to rules and procedures prescribed by the Company, to reallocate amounts deemed invested in Spectra Energy Corp common stock under the SECS Investment Option to any other open investment option. The SECS Investment Option shall be closed to additional deferrals and to transfers from any other investment option

(iv) Capitalized terms used in this Section 4.5 that are not defined in this Plan shall have the meaning set forth in the Employee Matters Agreement by and between Duke Energy Corporation and Spectra Energy Corp "

2. Article XI of the Plan is hereby amended by adding the following new Section 11 5 at the end thereof:

"11.5 The Account of each member of the Board of Directors of Spectra Energy Corp or its predecessor companies (a "Spectra Energy Participant") maintained under the Plan immediately prior to the Distribution Date shall be transferred to the Spectra Energy Corp Directors' Savings Plan and assumed by Spectra Energy Corp as of the Distribution Date (the "Assumed Amounts"). For purposes of this Plan, the term "Assumed Amounts" shall include any amount of Compensation of a Spectra Energy Participant that is earned but not yet paid as of the Distribution Date and Phantom Stock Units granted to a Spectra Energy Participant under the Duke Energy Corporation 1998 Long-Term Incentive Plan, that were properly deferred by a Spectra Energy Participant under the Plan but that had not yet been credited to his or her Account under the Plan as of the Distribution Date. Each such Spectra Energy Participant shall have no further rights under the Plan immediately after his or her Account is transferred to the Spectra Energy Corp Directors' Savings Plan and assumed by Spectra Energy Corp in accordance with the terms and conditions of the Employee Matters Agreement by and between Duke Energy Corporation and Spectra Energy Corp (the "Employee Matters Agreement"). Capitalized terms used in this Section 11 5 that are not defined in this Plan shall have the meaning set forth in the Employee Matters Agreement."

3. Except as explicitly set forth herein, the Plan will remain in full force and effect.

This amendment has been executed by an authorized officer of Duke Energy Corporation on December 19, 2006.

DUKE ENERGY CORPORATION

By: /s/ CHRISTOPHER C. ROLFE
Christopher C. Rolfe
Group Executive and
Chief Administrative Officer

AMENDMENT TO THE

CINERGY CORP. EXCESS PENSION PLAN

The Cinergy Corp. Excess Pension Plan, as amended and restated effective as of January 1, 1998, and as amended from time to time (the "Plan"), is hereby amended effective as of January 1, 2007

(1) Explanation of Amendment

The Plan is amended to clarify the relationship between the Plan and the Cinergy Corp. Non-Union Employees' Pension Plan ("Cinergy's Pension Plan") in light of the adoption of the Duke Energy cash balance formula under Cinergy's Pension Plan.

(2) Amendment

Section 5.3 of the Plan is hereby amended in its entirety to read as follows:

"5.3 *Cash Balance Death Benefit*

The following rules shall apply upon the death of a Participant who is classified as a "Cash Balance Participant" or "Duke Account Participant" under Cinergy's Pension Plan:

(a) *Spouse Beneficiary.* If a death benefit is payable under Article 6 of Cinergy's Pension Plan or Article GV of Addendum G of Cinergy's Pension Plan on account of the Participant's death and the Participant's Beneficiary (as defined in Cinergy's Pension Plan) at the date of the Participant's death is his Spouse, such Spouse shall receive a death benefit in an amount equal to the Actuarial Equivalent (as defined in Cinergy's Pension Plan) of the benefits that would otherwise have been payable to the Participant under the Plan. The form of the death benefit payable to the Spouse under the Plan shall be the same form in which the Spouse's benefit is payable under Cinergy's Pension Plan. The payment of the Spouse's death benefit under the Plan shall be made, or shall commence, as of the same date as the Spouse's benefit under Cinergy's Pension Plan is made or commences.

(b) *Non-Spouse Beneficiary.* If a death benefit is payable under Article 6 of Cinergy's Pension Plan or under Article GV of Addendum G of Cinergy's Pension Plan on account of the Participant's death and the Participant's Beneficiary (as defined in Cinergy's Pension Plan) at the date of the Participant's death is any person other than the Participant's Spouse, such Beneficiary shall receive a death benefit in an amount equal to the Actuarial Equivalent (as defined in Cinergy's Pension Plan) of the benefits that would otherwise have been payable to the Participant under the Plan. The death benefit shall be payable in the form of a single lump sum cash payment and shall be made as soon as administratively practicable following the Participant's death."

IN WITNESS WHEREOF, Cinergy Corp. has caused this Amendment to be executed effective as of the date set forth herein.

By: /s/ CHRISTOPHER C. ROLFE
Christopher C. Rolfe
Group Executive and
Chief Administrative Officer

AMENDMENT TO

CINERGY CORP. 401(K) EXCESS PLAN

The Cinergy Corp. 401(k) Excess Plan (the "Plan") is amended, effective as of December 18, 2006, as follows:

1. Section 2.1 of the Plan is hereby amended by adding the following at the end thereof:

"(ff) "Duke Energy Common Stock—Stock Deferrals Account" means, with respect to a Participant, the bookkeeping account established and maintained pursuant to Section 3.2(e)(iv).

(gg) "Duke Formula Employee" has the meaning given to such term in the 401(k) Plan.

Capitalized terms that are not defined in Article II shall have the meaning set forth in the Company's 2006 Long-Term Incentive Plan."

2. Section 3.2 of the Plan is hereby amended by adding the following new subsections (e) and (f) at the end thereof:

"(e) *Deferrals of Stock Awards*. Each eligible Participant may irrevocably elect to defer, in accordance with the terms of this Plan, the entire amount of any nonvested Award granted under a long-term incentive plan sponsored by the Company (including the Company's 2006 Long-Term Incentive Plan), subject to the following conditions:

(i) Except as otherwise provided in this Section, the deferral election shall be made by, and shall become irrevocable as of, December 31 (or such earlier date as specified by the Committee) of the calendar year next preceding the calendar year for which such Award is granted, or at such later time as is permitted by the Committee, consistent with Section 409A of the Code, during the calendar year in which a Participant initially becomes eligible for the Plan.

(ii) To the extent permitted by the Committee, and except as otherwise provided in Section 3.2(e)(iii), with respect to an Award that is subject to a forfeiture condition requiring the Participant's continued services for a period of at least thirteen (13) months from the date that the service provider obtains a "legally binding right" to such Award (within the meaning of Section 409A of the Code), the deferral election shall be made by, and shall become irrevocable as of, the thirtieth (30th) day following the date that the Participant obtains the legally binding right to such Award.

(iii) To the extent permitted by the Committee, with respect to an Award that constitutes "performance-based compensation" (within the meaning of Section 409A of the Code), the deferral election shall be made by, and shall become irrevocable as of, the date that is 6 months before the end of the applicable performance period (or such earlier date as specified by the Committee), provided that in no event may such deferral election be made after such Award has become both substantially certain to be paid and readily ascertainable (within the meaning of Section 409A of the Code).

(iv) Upon the date that an Award that the Participant has elected to defer would otherwise have been payable, the number of shares of stock or the cash payment that would have become so payable but for the deferral election shall be converted into an equal number of units in the Duke Energy Common Stock—Stock Deferrals Account.

(v) Dividend Equivalents, to the extent deferred, shall also be credited to the Participant's Duke Energy Common Stock—Stock Deferrals Account commencing on the payment date of the first cash dividend of Company Stock that is declared after the date on which the deferred Award vests.

(vi) No deferral of a stock option or restricted stock award shall be permissible.

(f) *Dividend Equivalents Deferrals*. Each eligible Participant may irrevocably elect to defer, in accordance with the terms of this Plan, 100% of the amounts that would otherwise become payable as Dividend Equivalents, with respect to (i) an Award that is designated in the Award Agreement as a "Chairman's Award," or (ii) an Award with respect to which the Award Agreement specifically provides for the deferral of Dividend Equivalents. Such election must be made by the Participant at the time the Participant elects to defer receipt of the related Award pursuant to the terms of Section 3.2(e). Dividend Equivalents that have been deferred pursuant to the first sentence of this Section and credited to the Participant's Account shall be credited to the Participant's Duke Energy Common Stock—Stock Deferrals Account as of the dates such amounts would otherwise become payable pursuant to such award."

3. Section 3.3 of the Plan is hereby superseded and replaced in its entirety as set forth below:

"3.3 *Employer Base Matching Contributions*.

(a) If an Eligible Employee other than a Duke Formula Employee is entitled to a "Base Matching Contribution" under his or her 401(k) Plan, the Employer shall make an Employer Base Matching Contribution to the Participant's Matching Account equal to the amount of the Participant's "Base Matching Contribution" computed in accordance with the 401(k) Plan (prior to the limitation of Code Paragraph 401(m)(2)), but using the Participant's Compensation as defined in this Plan.

(b) If an Eligible Employee that is also a Duke Formula Employee is entitled to a "Base Matching Contribution" under his or her 401(k) Plan, the Employer shall make an Employer Base Matching Contribution to the Participant's Matching Account equal to the amount, if any, by which the lesser of the amounts in subparagraph (i) or (ii) below, exceeds the amount in subparagraph (iii) below:

(i) The maximum matching contribution the Participant was eligible to receive for the Plan Year under the 401(k) Plan based upon the Participant's "Compensation" as defined in the 401(k) Plan for the Plan Year, but determined without regard to the limitations of Code Paragraph 401(a)(17) and any deferral of Compensation pursuant to Section 3.2 of this Plan or bonuses pursuant to the Cinergy Corp. Nonqualified Deferred Incentive Compensation Plan.

(ii) The Participant's "Deferred Compensation Contribution" as defined under the 401(k) Plan for the Plan Year, plus the Participant's deferral of Compensation pursuant to Section 3.2 of this Plan or deferral of bonus pursuant to the Cinergy Corp. Nonqualified Deferred Incentive Compensation Plan during the Plan Year.

(iii) The "Base Matching Contribution" credited to the Participant's account under the 401(k) Plan for the Plan Year.

(c) If the Participant becomes a Duke Formula Employee during a Plan Year, the Committee shall prorate the amount of his or her Base Matching Contribution for the Plan Year based on the preceding provisions of this Section."

4. Section 3.5 of the Plan is hereby amended by inserting the words "a Duke Energy Common Stock—Stock Deferrals Account," immediately after the phrase "a Deferral Account,".

5. Section 4.1 of the Plan is hereby amended by inserting the words "Duke Energy Common Stock—Stock Deferrals Account," immediately after the phrase "Deferral Account,".

6. Section 4.2(a) of the Plan is hereby amended by adding the following sentence at the end thereof.

"The amounts in the Duke Energy Common Stock—Stock Deferrals Account shall be credited and maintained as units of a phantom investment that mirror the performance of Company Stock (with cash dividends reinvested)."

7. Section 4.2(b) of the Plan is hereby amended by adding the following sentence at the end thereof:

"Notwithstanding anything contained herein to the contrary, no transfers may be made into or out of the Duke Energy Common Stock—Stock Deferrals Account."

8. Section 4.2 of the Plan is hereby amended by adding the following new subsection (d) at the end thereof:

"(d) If there shall occur any merger, consolidation, liquidation, issuance of rights or warrants to purchase securities, recapitalization, reclassification, stock dividend, spin-off, split-off, stock split, reverse stock split or other distribution with respect to the shares of Company Stock, or any similar corporate transaction or event in respect of such shares, then the Committee shall, in the manner and to the extent that it deems appropriate and equitable to the Participants and consistent with the terms of this Plan, cause a proportionate adjustment to be made in number and kind of phantom investment units of shares of Company Stock deemed held under the Plan. Moreover, in the event of any such transaction or event, the Committee, in its discretion, may provide in substitution for any or all phantom investment units of shares of Company Stock such alternative consideration as it, in good faith, may determine to be equitable under the circumstances."

9. Section 4.3(b) of the Plan is hereby superseded and replaced in its entirety as set forth below:

"(b) The Employer Base Matching Contribution under Section 3.3 of this Plan shall be credited to a Participant's Matching Account in terms of cash as of the last day of each Plan Year. An Eligible Employee does not need to make deferrals pursuant to Section 3.2 (Election to Defer) of this Plan to receive Employer Base Matching Contributions."

10. Section 4.3(e) of the Plan is hereby amended by inserting the words "Duke Energy Common Stock—Stock Deferrals Account," immediately after the phrase "Deferral Account,".

11. The second sentence of Section 4.4(a) of the Plan is hereby amended by inserting the words "Duke Energy Common Stock—Stock Deferrals Accounts," immediately after the phrase "Deferral Accounts,".

12. Section 5.1(d) of the Plan is hereby amended by adding the following new subparagraph (4) at the end thereof:

"(4) Amounts credited as units to each Participant's Duke Energy Common Stock—Stock Deferrals Account shall be converted to and distributed in the form of whole shares of Company Stock and cash for any fractional share. To the extent that the delivery of any shares of Company Stock to a Participant under this Section 5.1(d)(4) otherwise would cause all or any portion of the Plan to be considered an "equity compensation plan" as such term is defined in Section 303A(8) of the New York Stock Exchange Listed Company Manual or any successor rule ("Listed Company Manual"), then such shares shall be paid from, and shall count against the share reserve of, a Company-sponsored "equity compensation plan" designated by the Committee that complies with the shareholder approval requirements contained in the Listed Company Manual."

13. Except as explicitly set forth herein, the Plan will remain in full force and effect.
This amendment has been approved and signed by an authorized officer of Duke Energy Corporation as of the date specified above.

DUKE ENERGY CORPORATION

By: /s/ CHRISTOPHER C. ROLFE
Christopher C. Rolfe
Group Executive and Chief
Administrative Officer

AMENDMENT TO

CINERGY CORP. EXCESS PROFIT SHARING PLAN

The Cinergy Corp. Excess Profit Sharing Plan (the "Plan") is amended, effective as of December 19, 2006, as follows:

1. Section 4.2 of the Plan is hereby amended by adding the following new paragraph (d) at the end thereof:

"(d) Notwithstanding anything contained herein to the contrary, each phantom unit of Duke Energy Corporation common stock (held in the account formerly known as the Cinergy Corp. Common Stock Fund, which has been renamed the Duke Energy Common Stock Fund) credited to a Participant's Account on the Distribution Date shall be converted, as of the Distribution Date, into phantom units of Spectra Energy Corp common stock and phantom units of Duke Energy Corporation common stock and reallocated as follows:

(1) The number of phantom units of Spectra Energy Corp common stock shall be equal to the number of shares of Spectra Energy Corp common stock to which the Participant would have been entitled on the Distribution had the phantom units of Duke Energy Corporation common stock represented actual shares of Duke Energy Corporation common stock as of the Record Date, the resulting number of phantom units of Spectra Energy Corp common stock being rounded down to the nearest whole unit.

(2) The resulting number of phantom units of Spectra Energy Corp common stock shall automatically be transferred from the Duke Energy Corporation Common Stock Fund and credited to a separate Investment Option that corresponds to the performance of Spectra Energy Corp common stock (the "Spectra Investment Option"), effective as of the Distribution Date.

(3) A Participant may elect, pursuant to rules and procedures prescribed by the Committee, to reallocate amounts deemed invested in the Spectra Investment Option into any other open Investment Option. The Spectra Investment Option shall be closed to additional deferrals and to transfers from any other Investment Option.

(4) Capitalized terms used in this Section 4.2(d) that are not defined in this Plan shall have the meaning set forth in the Employee Matters Agreement by and between Duke Energy Corporation and Spectra Energy Corp."

2. Except as explicitly set forth herein, the Plan will remain in full force and effect.

IN WITNESS WHEREOF, Cinergy Corp. has caused this Amendment to be executed and approved effective as of the date set forth herein.

By: /s/ CHRISTOPHER C. ROLFE
Christopher C. Rolfe
Group Executive and Chief
Administrative Officer

Date: 12/19/06

Exhibit 10.67

AMENDMENT TO

CINERGY CORP. 401(K) EXCESS PLAN

The Cinergy Corp. 401(k) Excess Plan (the "Plan") is amended, effective as of December 19, 2006, as follows:

1. Section 4.2 of the Plan is hereby amended by adding the following new paragraph (c) at the end thereof:

"(c) Notwithstanding anything contained herein to the contrary, each phantom unit of Company Stock credited to a Participant's Account on the Distribution Date shall be converted, as of the Distribution Date, into phantom units of Spectra Energy Corp common stock and phantom units of Company Stock and reallocated as follows:

(1) The number of phantom units of Spectra Energy Corp common stock shall be equal to the number of shares of Spectra Energy Corp common stock to which the Participant would have been entitled on the Distribution had the phantom units of Company Stock represented actual shares of the Company as of the Record Date, the resulting number of phantom units of Spectra Energy Corp common stock being rounded down to the nearest whole unit.

(2) The resulting number of phantom units of Spectra Energy Corp common stock shall automatically be transferred from the Company Stock Investment Option and credited to a separate Investment Option that corresponds to the performance of Spectra Energy Corp common stock (the "Spectra Investment Option"), effective as of the Distribution Date.

(3) A Participant may elect, pursuant to rules and procedures prescribed by the Company, to reallocate amounts deemed invested in the Spectra Investment Option into any other open Investment Option. The Spectra Investment Option shall be closed to additional deferrals and to transfers from any other Investment Option.

(4) Capitalized terms used in this Section 4.2(c) that are not defined in this Plan shall have the meaning set forth in the Employee Matters Agreement by and between Duke Energy Corporation and Spectra Energy Corp."

2. Section 5.1(d) of the Plan is hereby amended by adding the following new sub-paragraph (3) at the end thereof:

"(3) *Spectra Energy Corp Common Stock*. The portion of a Participant's Account that is deemed invested in Spectra Energy Corp common stock at the time of distribution will be distributed in the form of cash in accordance with rules and procedures prescribed by the Company."

3. Except as explicitly set forth herein, the Plan will remain in full force and effect.

IN WITNESS WHEREOF, Cinergy Corp. has caused this Amendment to be executed and approved effective as of the date set forth herein.

By: /s/ CHRISTOPHER C. ROLFE
Christopher C. Rolfe
Group Executive and Chief
Administrative Officer

Date: 12/19/06

Exhibit 10.68

AMENDMENT TO

CINERGY CORP. DIRECTORS' DEFERRED COMPENSATION PLAN

The Cinergy Corp. Directors' Deferred Compensation Plan (the "Plan") is amended, effective as of December 19, 2006, as follows:

1. Section 4.3 of the Plan is hereby amended by adding the following new paragraph at the end thereof:

"Notwithstanding anything contained herein to the contrary, each phantom unit of Common Stock credited to a Participant's Unit Account on the Distribution Date shall be converted, as of the Distribution Date, into phantom units of Spectra Energy Corp common stock and phantom units of Common Stock and reallocated as follows:

(a) The number of phantom units of Spectra Energy Corp common stock shall be equal to the number of shares of Spectra Energy Corp common stock to which the Participant would have been entitled on the Distribution had the phantom units of Common Stock represented actual shares of Duke Energy Corporation as of the Record Date, the resulting number of phantom units of Spectra Energy Corp common stock being rounded down to the nearest whole unit.

(b) The resulting number of phantom units of Spectra Energy Corp common stock shall automatically be transferred from the Unit Account and credited to a separate individual account established and maintained for the exclusive purpose of accounting for the Participant's deferred amounts which is accrued in terms of a theoretical number of units of Spectra Energy Corp common stock (the "Spectra Unit Account"), effective as of the Distribution Date. The Spectra Unit Account shall thereafter be subject to the same adjustment provisions related to cash dividends and changes in Spectra Energy Corp common stock as apply to the Unit Account in Section 4.3 hereof.

(c) A Participant may elect, pursuant to rules and procedures prescribed by Duke Energy Corporation, to reallocate amounts deemed invested in the Spectra Unit Account into the Unit Account or the Deferred Compensation Account The Spectra Unit Account shall be closed to additional deferrals and to transfers from any other deemed investment option.

(d) Capitalized terms used in this Section 4.3 that are not defined in this Plan shall have the meaning set forth in the Employee Matters Agreement by and between Duke Energy Corporation and Spectra Energy Corp "

2. Article 6 of the Plan is hereby amended by adding the following new Section 6.4 at the end thereof:

"6.4 *Payment of Deferred Fees Credited to the Spectra Unit Account* Notwithstanding anything contained in this Article 6 or Article 8 to the contrary, the amounts credited to a Participant's Spectra Unit Account will be distributed in the form of cash."

3. Except as explicitly set forth herein, the Plan will remain in full force and effect.

IN WITNESS WHEREOF, Cinergy Corp has caused this Amendment to be executed and approved effective as of the date set forth herein.

By: /s/ CHRISTOPHER C. ROLFE
Christopher C. Rolfe
Group Executive and Chief
Administrative Officer

Date: 12/19/06

COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES

The ratio of earnings to fixed charges is calculated using the Securities and Exchange Commission guidelines [a].

	Year Ended December 31,				
	2006	2005	2004	2003	2002
	(dollars in millions)				
Earnings as defined for fixed charges calculation					
Add:					
Pretax (loss) income from continuing operations[b][e]	$2,192	$3,869	$1,792	$ (307)	$1,526
Fixed charges	1,382	1,159	1,433	1,620	1,550
Distributed income of equity investees	893	473	140	263	369
Deduct:					
Preference security dividend requirements of consolidated subsidiaries	27	27	31	139	170
Interest capitalized[c]	56	23	18	58	193
Total earnings (as defined for the Fixed Charges calculation)	$4,384	$5,451	$3,316	$1,379	$3,082
Fixed charges:					
Interest on debt, including capitalized portions	$1,311	$1,096	$1,365	$1,441	$1,340
Estimate of interest within rental expense	44	36	37	40	40
Preference security dividend requirements of consolidated subsidiaries	27	27	31	139	170
Total fixed charges	$1,382	$1,159	$1,433	$1,620	$1,550
Ratio of earnings to fixed charges[e]	3.2	4.7	2.3	(d)	2.0

(a) Certain prior year Income Statement amounts above have been adjusted for businesses reclassified to discontinued operations during 2006.

(b) Excludes minority interest expenses and income or loss from equity investees.

(c) Excludes equity costs related to Allowance for Funds Used During Construction that are included in Other Income and Expenses in the Consolidated Statements of Operations.

(d) Earnings were inadequate to cover fixed charges by $241 million for the year ended December 31, 2003.

(e) Includes pre-tax gains on the sale of TEPPCO GP and LP of approximately $0.9 billion, net of minority interest, in 2005.

LIST OF SUBSIDIARIES

The following is a list of certain subsidiaries (greater than 50% owned) of the registrant and their respective states or countries of incorporation:

1388368 Ontario Inc. (Ontario)
3036243 Nova Scotia Company (Canada—Nova Scotia)
Advance SC LLC (South Carolina)
Aguaytia Energy del Peru S R. Ltda (Peru)
Aguaytia Energy, LLC
Antelope Ridge Gas Processing Plant
Attiki Denmark ApS (Denmark)
Bison Insurance Company Limited (Bermuda)
Brown County Landfill Gas Associates, L.P. (Delaware)
Brownsville Power I, LLC (Delaware)
BSPE General, LLC (Texas)
BSPE Holdings, LLC (Delaware)
BSPE Limited, LLC (Delaware)
BSPE, L.P. (Delaware)
Cadence Network, Inc (Delaware)
Caldwell Power Company (North Carolina)
Catawba Manufacturing and Electric Power Company (North Carolina)
Centra Gas Toluca S De R L. De D.V (Mexico)
CGP Global Greece Holdings, SA (Greece)
Cinergy Capital & Trading, Inc. (Indiana)
Cinergy Climate Change Investments, LLC (Delaware)
Cinergy Corp (Delaware)
Cinergy General Holdings, LLC (Delaware)
Cinergy Global (Cayman) Holdings, Inc (Cayman Islands)
Cinergy Global Ely, Inc. (Delaware)
Cinergy Global Hellas S A. (Greece)
Cinergy Global Holdings, Inc. (Delaware)
Cinergy Global Power (UK) Limited (England)
Cinergy Global Power Africa (Proprietary) Limited (South Africa)
Cinergy Global Power Iberia, S.A. (Spain)
Cinergy Global Power Services Limited (London, England)
Cinergy Global Power, Inc. (Delaware)
Cinergy Global Resources, Inc. (Delaware)
Cinergy Global Trading Limited (England)
Cinergy Global Tsavo Power (Cayman Islands)
Cinergy Holdings BV (Netherlands)
Cinergy Investments, Inc. (Delaware)
Cinergy Limited Holdings, LLC (Delaware)
Cinergy Mexico General, LLC (Delaware)
Cinergy Mexico Holdings, LP (Delaware)
Cinergy Mexico Limited, LLC (Delaware)
Cinergy Mexico Marketing & Trading, LLC (Delaware)
Cinergy Origination & Trade, LLC (Delaware)
Cinergy Power Generation Services, LLC (Delaware)
Cinergy Power Investments, Inc. (Ohio)
Cinergy Receivables Company LLC (Delaware)
Cinergy Retail Power General, Inc (Texas)
Cinergy Retail Power Limited, Inc. (Delaware)
Cinergy Retail Power, L.P. (Delaware)
Cinergy Risk Solutions Ltd. (Vermont)
Cinergy Solutions—Utility, Inc. (Delaware)
Cinergy Solutions Limited Partnership (Ontario)
Cinergy Solutions Partners, LLC (Delaware)
Cinergy Technology, Inc. (Indiana)
Cinergy Two, Inc. (Delaware)
Cinergy UK, Inc. (Delaware)
Cinergy Wholesale Energy, Inc. (Ohio)
Cinergy-Centrus Communications, Inc. (Delaware)
Cinergy-Centrus, Inc. (Delaware)
CinFuel Resources, Inc. (Delaware)
CinPower I, LLC (Delaware)
Claiborne Energy Services, Inc. (Louisiana)
Comercializadora Duke Energy de Centro America, Limitada (Guatemala)
Commercial Electricity Supplies Limited (England)
Compania de Servicios de Compresion de Campeche, S.A. de C.V. (Mexico)
Countryside Landfill Gasco, LLC (Delaware)
CRE, LLC (Delaware)
CSCC Holdings Limited Partnership (Canada—British Columbia)
CSGP General, LLC (Texas)
CSGP Limited, LLC (Delaware)
CSGP of Southeast Texas, LLC (Delaware)
CSGP Services, L.P. (Delaware)
CST General, LLC (Texas)
CST Green Power, L.P. (Delaware)
CST Limited, LLC (Delaware)
CTE Petrochemicals Company (Cayman Islands)
D/FD Foreign Sales Corporation (Barbados)
D/FD Holdings, LLC (Delaware)
D/FD International Services Brasil Ltda. (Brazil)
D/FD Operating Services LLC (Delaware)
DE Fossil-Hydro Engineering, Inc. (North Carolina)
DE Marketing Canada Ltd. (Canadian Federal)

DE Nuclear Engineering, Inc. (North Carolina)
DE Operating Services, LLC (Delaware)
DE Power Generating, LLC (Delaware)
DEGS Biogas, Inc. (Delaware)
DEGS EPCOM College Park, LLC (Delaware)
DEGS GASCO, LLC (Delaware)
DEGS O&M, LLC (Delaware)
DEGS of Boca Raton, LLC (Delaware)
DEGS of Cincinnati, LLC (Ohio)
DEGS of Delta Township, LLC (Delaware)
DEGS of Lansing, LLC (Delaware)
DEGS of Monaca, LLC (Delaware)
DEGS of Narrows, LLC (Delaware)
DEGS of Oklahoma, LLC (Delaware)
DEGS of Parlin, LLC (Delaware)
DEGS of Philadelphia, LLC (Delaware)
DEGS of Rock Hill, LLC (Delaware)
DEGS of San Diego, Inc. (Delaware)
DEGS of Shreveport, LLC (Delaware)
DEGS of South Charleston, LLC (Delaware)
DEGS of St. Bernard, LLC (Delaware)
DEGS of St. Paul, LLC (Delaware)
DEGS of Tuscola, Inc. (Delaware)
Delta Township Utilities, LLC (Delaware)
DENA Asset Partners, L.P. (Delaware)
DENA Partners Holding, LLC (Delaware)
DETM Marketing Northeast, LLC (Delaware)
DETMI Management, Inc. (Colorado)
Dixilyn-Field (Nigeria) Limited (Nigeria)
Dixilyn-Field Drilling Company (Delaware)
Dixilyn-Field International Drilling Company, S.A. (Panama)
DTMSI Management Ltd. (Alberta, Canada)
Duke Broadband, LLC (Delaware)
Duke Canada Ltd. (Alberta, Canada)
Duke Capital Partners, LLC (Delaware)
Duke Communication Services Caribbean Ltd. (Bermuda)
Duke Communication Services, Inc. (North Carolina)
Duke Communications Holdings, Inc. (Delaware)
Duke Energy Allowance Management, LLC (Delaware)
Duke Energy Americas, LLC (Delaware)
Duke Energy Business Services LLC (Delaware)
Duke Energy Carolinas Plant Operations, LLC (Delaware)
Duke Energy Carolinas, LLC (North Carolina)
Duke Energy Development Pty Ltd (Australia)
Duke Energy Egenor S. en C. por A. (Peru)
Duke Energy Electroquil Partners (Delaware)
Duke Energy Engineering, Inc. (Ohio)
Duke Energy Finance Canada Limited Partnership (Canada—Alberta)
Duke Energy Fossil-Hydro California, Inc. (Delaware)
Duke Energy Fossil-Hydro, LLC (Delaware)
Duke Energy Generating S.A. (Argentina)
Duke Energy Generation Services Holding Company, Inc. (Delaware)
Duke Energy Generation Services, Inc. (Delaware)
Duke Energy Global Markets, Inc. (Nevada)
Duke Energy Greenleaf, LLC (Delaware)
Duke Energy Group Holdings, LLC (Delaware)
Duke Energy Group, LLC (Delaware)
Duke Energy Hydrocarbons Canada Limited Partnership (Canada)
Duke Energy Hydrocarbons Investments Ltd. (Canada—Alberta)
Duke Energy Indiana, Inc. (Indiana)
Duke Energy Industrial Sales, LLC (Delaware)
Duke Energy Interamerican Holding Company LDC (Cayman Islands)
Duke Energy International (Europe) Holdings ApS (Denmark)
Duke Energy International (Europe) Limited (United Kingdom)
Duke Energy International Argentina Holdings (Cayman Islands)
Duke Energy International Argentina Marketing/Trading (Bermuda) Ltd. (Bermuda)
Duke Energy International Asia Pacific Ltd. (Bermuda)
Duke Energy International Bolivia Holdings No. 1, LLC (Delaware)
Duke Energy International Bolivia Investments No. 1 Limited (Cayman Islands)
Duke Energy International Bolivia Investments No. 2 Limited (Cayman Islands)
Duke Energy International Brasil Commercial, Ltda. (Brazil)
Duke Energy International Brasil Holdings, LLC (Delaware)
Duke Energy International Brazil Holdings Ltd. (Bermuda)
Duke Energy International del Ecuador Cia. Ltda. (Ecuador)
Duke Energy International El Salvador Comercializadora de El Salvador, S.A. de C.V. (El Salvador)
Duke Energy International El Salvador Investments No. 1 Ltd (Bermuda)
Duke Energy International El Salvador Investments No. 1 y Cia. S. enC. de C.V. (El Salvador)
Duke Energy International El Salvador, S en C de CV (El Salvador)
Duke Energy International Electroquil Holdings, LLC (Delaware)
Duke Energy International Espana Holdings, S.L. (Spain)
Duke Energy International Finance (UK) Limited (United Kingdom)
Duke Energy International Guatemala Holdings No. 1, Ltd. (Bermuda)
Duke Energy International Guatemala Holdings No. 2, Ltd. (Bermuda)
Duke Energy International Guatemala Holdings No. 3 (Cayman Islands)

Duke Energy International Guatemala Limitada (Guatemala)

Duke Energy International Guatemala y Compania Sociedad en Comandita por Acciones (Guatemala)

Duke Energy International Investments No. 2 Ltd. (Bermuda)

Duke Energy International Latin America, Ltd. (Bermuda)

Duke Energy International Mexico, S.A. de C.V. (Mexico)

Duke Energy International Netherlands Financial Services B.V. (Netherlands)

Duke Energy International Operaciones Guatemala Limitada (Guatemala)

Duke Energy International Peru Inversiones No. 1, S.R.L. (Peru)

Duke Energy International Peru Investments No. 1, Ltd. (Bermuda)

Duke Energy International PJP Holdings (Mauritius) Ltd. (Republic of Mauritius)

Duke Energy International PJP Holdings, Ltd. (Bermuda)

Duke Energy International Pty Ltd (Australia)

Duke Energy International Services (UK) Limited (United Kingdom)

Duke Energy International Southern Cone SRL (Argentina)

Duke Energy International Trading and Marketing (UK) Limited (United Kingdom)

Duke Energy International Transmision Guatemala Limitada (Guatemala)

Duke Energy International Uruguay Holdings, LLC (Delaware)

Duke Energy International Uruguay Investments, S.R.L. (Uruguay)

Duke Energy International, Brasil Ltda. (Brazil)

Duke Energy International, Geracao Paranapanema S.A. (Brazil)

Duke Energy International, LLC (Delaware)

Duke Energy Kentucky, Inc. (Kentucky)

Duke Energy Lantana, LLC (Delaware)

Duke Energy Marketing America, LLC (Delaware)

Duke Energy Marketing Canada Corp. (Delaware)

Duke Energy Marketing Corp. (Nevada)

Duke Energy Marketing Limited Partnership (Alberta, Canada)

Duke Energy Merchant Finance, LLC (Delaware)

Duke Energy Merchants Investments (UK) Limited (England and Wales)

Duke Energy Merchants Trading and Marketing (UK) Limited (England)

Duke Energy Merchants UK LLP (England and Wales)

Duke Energy Merchants, LLC (Delaware)

Duke Energy Moapa, LLC (Delaware)

Duke Energy Murray Operating, LLC (Delaware)

Duke Energy North America, LLC (Delaware)

Duke Energy Ohio, Inc. (Ohio)

Duke Energy One, Inc. (Delaware)

Duke Energy Peru Holdings S.R.L. (Peru)

Duke Energy Power Assets Holding, Inc. (Colorado)

Duke Energy Providence, LLC (Delaware)

Duke Energy Receivables Finance Company, LLC (Delaware)

Duke Energy Registration Services, Inc. (Delaware)

Duke Energy Retail Sales, LLC (Delaware)

Duke Energy Royal, LLC (Delaware)

Duke Energy Services Canada Ltd. (Alberta—Canada)

Duke Energy Services Ireland Limited (Republic of Ireland)

Duke Energy Services, Inc. (Delaware)

Duke Energy Shared Services, Inc. (Delaware)

Duke Energy St. Francis, LLC (Delaware)

Duke Energy Supply Chain Services, LLC (Delaware)

Duke Energy Trading and Marketing, LLC (Delaware)

Duke Energy Trading Exchange, LLC (Delaware)

Duke Engineering & Services (Europe) Inc. (Delaware)

Duke Engineering & Services International, Inc. (Cayman Islands)

Duke Investments, LLC (Delaware)

Duke Java, Inc. (Nevada)

Duke Project Services Australia Pty Ltd (Australia)

Duke Project Services, Inc. (North Carolina)

Duke Supply Network, LLC (Delaware)

Duke Technologies, Inc. (Delaware)

Duke Trading Do Brasil Ltda. (Brazil)

Duke Ventures II, LLC (Delaware)

Duke Ventures, LLC (Nevada)

Duke/Fluor Daniel (North Carolina)

Duke/Fluor Daniel Caribbean, S.E. (Puerto Rico)

Duke/Fluor Daniel El Salvador S.A. de C.V. (El Salvador)

Duke/Fluor Daniel International (Nevada)

Duke/Fluor Daniel International Services (Nevada)

Duke/Fluor Daniel International Services (Trinidad) Ltd. (Trinidad and Tobago)

Duke/Louis Dreyfus LLC (Nevada)

Duke-Cadence, Inc. (Indiana)

DukeNet Communication Services, LLC (Delaware)

DukeNet Communications, LLC (Delaware)

Duke-Reliant Resources, Inc. (Delaware)

DukeTec I, LLC (Delaware)

DukeTec II, LLC (Delaware)

DukeTec, LLC (Delaware)

Eastman Whipstock do Brasil Ltda. (Brazil)

Eastman Whipstock, S.A. (Argentina)

Eastover Land Company (Kentucky)

Eastover Mining Company (Kentucky)

Electroguayas, Inc. (Cayman Islands)

Electroquil, S.A. (Guayaquil, Ecuador)

Empresa Electrica Corani, S.A. (Bolivia)

Energy Pipelines International Company (Delaware)
EnerVest Olanta, LLC (Texas)
Environmental Wood Supply, LLC (Minnesota)
Eteselva S. R. L. (Peru)
eVent Resources Holdings LLC (Delaware)
eVent Resources I LLC (Delaware)
Fiber Link, LLC (Indiana)
Fort Drum Cogenco, Inc. (New York)
Gas Integral S.R.L. (Peru)
Generadora La Laguna Duke Energy International Guatemala y Cia., S.C.A (Guatemala)
GNE Holdings, LLC (Delaware)
Green Power G.P., LLC (Delaware)
Green Power Holdings, LLC (Delaware)
Green Power Limited, LLC (Delaware)
Greenville Gas and Electric Light and Power Company (South Carolina)
Hidroelectrica Cerros Colorados, S.A. (Argentina)
IGC Aguaytia Partners, LLC (Cayman Islands)
II Tryon Investment Trading Society (North Carolina)
Inversiones Duke Bolivia S.A. (Bolivia)
KO Transmission Company (Kentucky)
Lansing Grand River Utilities, LLC (Delaware)
LH1, LLC (Delaware)
Lizacorp S.A. (Ecuador)
MCP, LLC (South Carolina)
Miami Power Corporation (Indiana)
Midlands Hydrocarbons (Bangladesh) Limited (England)
Morris Gasco, LLC (Delaware)
MP Supply, Inc. (North Carolina)
National Methanol Company (IBN SINA) (Saudi Arabia)
NorthSouth Insurance Company Limited (Bermuda)
Oak Mountain Products, LLC (Delaware)
Ohio River Valley Propane, LLC (Delaware)
P.I.D.C. Aguaytia, LLC (Delaware)
Pan Service Company (Delaware)
PanEnergy Corp (Delaware)
Peru Energy Holdings, LLC (Delaware)
Power Construction Services Pty Ltd. (Western Australia)
Reliant Services, LLC (Indiana)
Seahorse do Brasil Servicos Maritimos Ltda. (Brazil)
South Construction Company, Inc. (Indiana)
South Houston Green Power, L.P. (Delaware)
Southeastern Energy Services, Inc. (Delaware)
Southern Power Company (North Carolina)
Spruce Mountain Investments, LLC (Delaware)
Spruce Mountain Products, LLC (Delaware)
St. Paul Cogeneration, LLC (Minnesota)
SUEZ/WWNA/DEGS of Lansing, LLC (Delaware)
SUEZ-DEGS of Lansing, LLC (Delaware)
SUEZ-DEGS of Orlando, LLC (Delaware)
SUEZ-DEGS, LLC (Delaware)
SYNCAP II, LLC (Delaware)
TEC Aguaytia, Ltd. (Bermuda)
Termoselva S. R. L. (Peru)
Texas Eastern (Bermuda) Ltd. (Bermuda)
Texas Eastern Arabian Ltd. (Bermuda)
Tri-State Improvement Company (Ohio)
UK Electric Power Limited (England)
Wateree Power Company (South Carolina)
Western Carolina Power Company (North Carolina)

EXHIBIT 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statements No. 333-132996 and 333-132992 on Form S-3 and Registration Statements No. 333-134080 and 333-132933 on Form S-8 of Duke Energy Corporation of our reports dated March 1, 2007, relating to the financial statements and financial statement schedule of Duke Energy Corporation (which report expresses an unqualified opinion and includes explanatory paragraphs regarding the adoption of a new accounting standard and the January 2, 2007 spin-off of the Company's natural gas businesses) and management's report on the effectiveness of internal control over financial reporting, appearing in this Annual Report on Form 10-K of Duke Energy Corporation for the year ended December 31, 2006.

/s/ DELOITTE & TOUCHE LLP

Charlotte, North Carolina

March 1, 2007

EXHIBIT 23.2

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Partners of TEPPCO Partners, L.P.:

We consent to the incorporation by reference in the registration statements Nos. 333-132996 and 333-132992 on Form S-3 and Nos. 333-134080 and 333-132933 on Form S-8 of Duke Energy Corporation of our report dated February 28, 2006, except for the effects of discontinued operations, as discussed in Note 5, which is as of June 1, 2006, with respect to the consolidated balance sheets of TEPPCO Partners, L.P. and subsidiaries as of December 31, 2005 and 2004, and the related consolidated statements of income, partners' capital and comprehensive income, and cash flows for each of the years in the three-year period ended December 31, 2005, which report appears herein.

Our report dated February 28, 2006, except for the effects of discontinued operations, as discussed in Note 5, which is as of June 1, 2006, with respect to the consolidated balance sheets of TEPPCO Partners, L.P. and subsidiaries as of December 31, 2005 and 2004 and the related consolidated statements of income, partners' capital and comprehensive income, and cash flows for each of the years in the three-year period ended December 31, 2005, contains a separate paragraph that states that as discussed in Note 20 to the consolidated financial statements, the Partnership has restated its consolidated balance sheet as of December 31, 2004, and the related consolidated statements of income, partners' capital and comprehensive income, and cash flows for the years ended December 31, 2004 and 2003.

/s/ KPMG LLP

Houston, Texas

March 1, 2007

Exhibit 24.1

DUKE ENERGY CORPORATION

Power of Attorney

FORM 10-K

Annual Report Pursuant to Section 13 or 15(d)

of the Securities Exchange Act of 1934

For the fiscal year ended December 31, 2006

~~(Annual Report)~~

The undersigned **Duke Energy Corporation**, a Delaware corporation and certain of its officers and/or directors, do each hereby constitute and appoint David L. Hauser, David S. Maltz and Steven K. Young, and each of them, to act as attorneys-in-fact for and in the respective names, places and stead of the undersigned, to execute, seal, sign and file with the Securities and Exchange Commission the Annual Report of said Duke Energy Corporation on Form 10-K and any and all amendments thereto, hereby granting to said attorneys-in-fact, and each of them, full power and authority to do and perform all and every act and thing whatsoever requisite, necessary or proper to be done in and about the premises, as fully to all intents and purposes as the undersigned, or any of them, might or could do if personally present, hereby ratifying and approving the acts of said attorneys-in-fact.

Executed as of the 27th day of February, 2007.

DUKE ENERGY CORPORATION

By: /s/ JAMES E. ROGERS

Chairman, President and

Chief Executive Officer

(Corporate Seal)

ATTEST:

/S/ SUE C. HARRINGTON

Assistant Secretary

/S/ JAMES E. ROGERS James E. Rogers	Chairman, President and Chief Executive Officer (Principal Executive Officer and Director)
/S/ DAVID L. HAUSER David L. Hauser	Group Executive and Chief Financial Officer (Principal Financial Officer)
/S/ STEVEN K. YOUNG Steven K. Young	Senior Vice President and Controller

	(Principal Accounting Officer)
/S/ WILLIAM BARNET, III William Barnet, III	(Director)
/S/ G ALEX BERNHARDT G. Alex Bernhardt	(Director)
/S/ MICHAEL G. BROWNING Michael G. Browning	(Director)
/S/ PHILLIP R. COX Phillip R. Cox	(Director)
/S/ ANN M. GRAY Ann M. Gray	(Director)

/s/ James H. Hance, Jr.	(Director)
James H. Hance, Jr.	
/s/ James T. Rhodes	(Director)
James T. Rhodes	
/s/ Mary L. Schapiro	(Director)
Mary L. Schapiro	
/s/ Dudley S. Taft	(Director)
Dudley S. Taft	

DUKE ENERGY CORPORATION

CERTIFIED RESOLUTIONS

Form 10-K Annual Report Resolutions

FURTHER RESOLVED, That each officer and director who may be required to execute such 2006 Form 10-K or any amendments thereto (whether on behalf of the Corporation or as an officer or director thereof or by attesting the seal of the Corporation or otherwise) be and hereby is authorized to execute a Power of Attorney appointing David L. Hauser, David S. Maltz and Steven K. Young, and each of them, as true and lawful attorneys and agents to execute in his or her name, place and stead (in any such capacity) such 2006 Form 10-K, as may be deemed necessary and proper by such officers, and any and all amendments thereto and all instruments necessary or advisable in connection therewith, to attest the seal of the Corporation thereon and to file the same with the Securities and Exchange Commission, each of said attorneys and agents to have power to act with or without the others and to have full power and authority to do and perform in the name and on behalf of each of such officers and directors, or both, as the case may be, every act whatsoever necessary or advisable to be done in the premises as fully and to all intents and purposes as any such officer or director might or could do in person.

****

I, JULIA S. JANSON, Senior Vice President, Ethics and Compliance and Corporate Secretary of Duke Energy Corporation, do hereby certify that the foregoing is a full, true and complete extract from the Minutes of the regular meeting of the Board of Directors of said Corporation held on February 27, 2007, at which meeting a quorum was present.

IN WITNESS WHEREOF, I have hereunto set my hand and affixed the Corporate Seal of said Duke Energy Corporation, this the 27 th day of February, 2007.

/s/ JULIA S. JANSON.

Julia S. Janson, Senior Vice President, Ethics and Compliance
and Corporate Secretary

CERTIFICATION OF THE CHIEF EXECUTIVE OFFICER

PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, James E. Rogers, certify that:

1) I have reviewed this annual report on Form 10-K of Duke Energy Corporation;

2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3) Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4) The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Acts Rules 13a - 15(f) and 15d - 15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that ~~material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the~~ period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5) The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 1, 2007

/s/ JAMES E. ROGERS

James E. Rogers

Chairman, President and

Chief Executive Officer

EXHIBIT 31.2

CERTIFICATION OF THE CHIEF FINANCIAL OFFICER

PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, David L. Hauser, certify that:

1) I have reviewed this annual report on Form 10-K of Duke Energy Corporation;

2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3) Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4) The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Acts Rules 13a – 15(f) and 15d – 15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that ~~material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the~~ period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5) The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 1, 2007

/s/ DAVID L. HAUSER

David L. Hauser

Group Executive and

Chief Financial Officer

EXHIBIT 32.1

CERTIFICATION PURSUANT TO

18 U.S.C. SECTION 1350,

AS ADOPTED PURSUANT TO

SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Duke Energy Corporation ("Duke Energy") on Form 10-K for the period ending December 31, 2006 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, James E. Rogers, Chairman, President and Chief Executive Officer of Duke Energy, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Duke Energy.

/s/ JAMES E. ROGERS

James E. Rogers

Chairman, President and Chief Executive Officer

March 1, 2007

EXHIBIT 32.2

CERTIFICATION PURSUANT TO

18 U.S.C. SECTION 1350,

AS ADOPTED PURSUANT TO

SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Duke Energy Corporation ("Duke Energy") on Form 10-K for the period ending December 31, 2006 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, David L Hauser, Group Executive and Chief Financial Officer of Duke Energy, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Duke Energy

/s/ DAVID L HAUSER

David L Hauser

Group Executive and Chief Financial Officer

March 1, 2007

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D C 20549

FORM 10-K

FOR ANNUAL AND TRANSITION REPORTS
PURSUANT TO SECTION 13 OR 15(d) OF THE
SECURITIES EXCHANGE ACT OF 1934

(Mark One)

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2006 or

☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from _________ to _________

Commission file number 1-32853

DUKE ENERGY CORPORATION

(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	20-2777218 (I R S Employer Identification No)
526 South Church Street, Charlotte, North Carolina (Address of principal executive offices)	28202-1803 (Zip Code)

704-594-6200
(Registrant's telephone number, including area code)

SECURITIES REGISTERED PURSUANT TO SECTION 12(B) OF THE ACT

Title of each class	Name of each exchange on which registered
Common Stock, without par value	New York Stock Exchange, Inc.

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act Yes ☒ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports) and (2) has been subject to such filing requirements for the past 90 days Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer (as defined in Rule 12b-2 of the Securities Exchange Act of 1934)
Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Securities Exchange Act of 1934) Yes ☐ No ☒

Estimated aggregate market value of the common equity held by nonaffiliates of the registrant at June 30, 2006	$36,684,000,000
Number of shares of Common Stock, $0 001 par value, outstanding at February 23, 2007	1,257,116,278

Table of Contents

TABLE OF CONTENTS

DUKE ENERGY CORPORATION
FORM 10-K FOR THE YEAR ENDED
DECEMBER 31, 2006

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

This document includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934 Forward-looking statements are based on management's beliefs and assumptions These forward-looking statements are identified by terms and phrases such as "anticipate," "believe," "intend," "estimate," "expect," "continue," "should," "could," "may," "plan," "project," "predict," "will," "potential," "forecast," and similar expressions Forward-looking statements involve risks and uncertainties that may cause actual results to be materially different from the results predicted Factors that could cause actual results to differ materially from those indicated in any forward-looking statement include, but are not limited to:

- State, federal and foreign legislative and regulatory initiatives, including costs of compliance with existing and future environmental requirements;
- Costs and effects of legal and administrative proceedings, settlements, investigations and claims;
- Industrial, commercial and residential growth in Duke Energy's service territories;
- Additional competition in electric markets and continued industry consolidation;
- Political and regulatory uncertainty in other countries in which Duke Energy conducts business;
- The influence of weather and other natural phenomena on Duke Energy operations, including the economic, operational and other effects of hurricanes and ice storms;
- The timing and extent of changes in commodity prices, interest rates and foreign currency exchange rates;
- Unscheduled generation outages, unusual maintenance or repairs and electric transmission system constraints,
- The results of financing efforts, including Duke Energy's ability to obtain financing on favorable terms, which can be affected by various factors, including Duke Energy's credit ratings and general economic conditions;
- Declines in the market prices of equity securities and resultant cash funding requirements for Duke Energy's defined benefit pension plans;
- The level of credit worthiness of counterparties to Duke Energy's transactions;
- Employee workforce factors, including the potential inability to attract and retain key personnel;
- Growth in opportunities for Duke Energy's business units, including the timing and success of efforts to develop domestic and international power and other projects;

- The performance of electric generation and of projects undertaken by Duke Energy's non-regulated businesses;
- The extent of success in connecting and expanding electric markets;
- The effect of accounting pronouncements issued periodically by accounting standard-setting bodies;
- The ability to successfully complete merger, acquisition or divestiture plans, including the prices at which Duke Energy is able to sell assets; and regulatory or other limitations imposed as a result of a merger

In light of these risks, uncertainties and assumptions, the events described in the forward-looking statements might not occur or might occur to a different extent or at a different time than Duke Energy has described. Duke Energy undertakes no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise

Table of Contents

PART I

Item 1. Business.

GENERAL

Duke Energy Corporation (collectively with its subsidiaries, Duke Energy) is an energy company located in the Americas Duke Energy provides its services through the business units described below

In May 2005, Duke Energy and Cinergy Corp (Cinergy) announced they entered into a definitive merger agreement Closing of the transaction occurred in the second quarter of 2006 The merger combined the Duke Energy and Cinergy regulated franchises as well as deregulated generation in the Midwest United States

Duke Energy Holding Corp (Duke Energy HC) was incorporated in Delaware on May 3, 2005 as Deer Holding Corp , a wholly-owned subsidiary of Duke Energy Corporation (Old Duke Energy). On April 3, 2006, in accordance with their previously announced merger agreement, Old Duke Energy and Cinergy merged into wholly-owned subsidiaries of Duke Energy HC, resulting in Duke Energy HC becoming the parent entity In connection with the closing of the merger transactions, Duke Energy HC changed its name to Duke Energy Corporation (New Duke Energy or Duke Energy) and Old Duke Energy converted into a limited liability company named Duke Power Company LLC (subsequently renamed Duke Energy Carolinas, LLC (Duke Energy Carolinas) effective October 1, 2006). As a result of the merger transactions, each outstanding share of Cinergy common stock was converted into 1 56 shares of common stock of Duke Energy, which resulted in the issuance of approximately 313 million shares Additionally, each share of common stock of Old Duke Energy was converted into one share of Duke Energy common stock Old Duke Energy is the predecessor of Duke Energy for purposes of U S securities regulations governing financial statement filing Therefore, the accompanying Consolidated Financial Statements reflect the results of operations of Old Duke Energy for the three months ended March 31, 2006 and the years ended December 31, 2005 and 2004 and the financial position of Old Duke Energy as of December 31, 2005 New Duke Energy had separate operations for the period beginning with the effective date of the Cinergy merger, and references to amounts for periods after the closing of the merger relate to New Duke Energy Cinergy's results have been included in the accompanying Consolidated Statements of Operations from the effective date of acquisition and thereafter (see "Cinergy Merger" in Note 2 to the Consolidated Financial Statements, "Acquisitions and Dispositions") Both Old Duke Energy and New Duke Energy are referred to as Duke Energy hereinafter

In conjunction with Duke Energy's merger with Cinergy, effective with the second quarter ended June 30, 2006, Duke Energy adopted new business segments that management believes properly align the various operations of Duke Energy with how the chief operating decision maker views the business Duke Energy operates the following business units: U S Franchised Electric and Gas, Natural Gas Transmission, Field Services, Commercial Power, International Energy and Duke Energy's 50% interest in the Crescent JV (Crescent) Prior to Duke Energy's sale of an effective 50% ownership interest in Crescent in September 2006 (see below), this segment represented Duke Energy's 100% ownership of Crescent Resources, LLC Duke Energy's chief operating decision maker regularly reviews financial information about each of these business units in deciding how to allocate resources and evaluate performance All of the Duke Energy business units are considered reportable segments under Statement of Financial Accounting Standards (SFAS) No 131, "Disclosures about Segments of an Enterprise and Related Information " (See Note 3 to the Consolidated Financial Statements, "Business Segments," for additional information, including financial information about each business unit and geographic areas)

Prior to the September 2005 announcement of the exiting of the majority of former Duke Energy North America's (DENA) businesses, former DENA's operations were considered a separate reportable segment The term DENA, as used throughout the Notes to Consolidated Financial Statements, refers to the former merchant generation operations in the Western and Eastern U S , as well as operations in the Midwest and Southeast Under Duke Energy's new segment structure, the merchant generation operations of the Midwest and Southeast are presented in continuing operations as a component of the Commercial Power segment for all periods presented and the Western and Eastern operations are presented as a component of discontinued operations within Other for all periods presented Prior to the change in business segments, former DENA's continuing operations, which primarily include the merchant generation operations in the Midwest and Southeast, were included in Other in 2005 and as a component of the DENA segment in all prior periods, and discontinued operations were included in the former DENA segment for all periods

U S Franchised Electric and Gas generates, transmits, distributes and sells electricity in central and western North Carolina, western South Carolina, southwestern Ohio, central and southern Indiana, and northern Kentucky U S Franchised Electric and Gas also transports and sells natural gas in southwestern Ohio and northern Kentucky It conducts operations primarily through Duke Energy Carolinas, Duke Energy Ohio, Inc (Duke Energy Ohio), Duke Energy Indiana, Inc (Duke Energy Indiana) and Duke Energy Kentucky, Inc (Duke Energy Kentucky) These electric and gas operations are subject to the rules and regulations of the Federal Energy Regulatory Commission (FERC), the North Carolina Utilities Commission (NCUC), the Public Service Commission of South Carolina (PSCSC), the Public Utilities Commission of Ohio (PUCO), the Indiana Utility Regulatory Commission (IURC) and the Kentucky Public Service Commission (KPSC)

PART I

Natural Gas Transmission provides transportation and storage of natural gas for customers in various regions of the Eastern and Southeastern United States, the Maritimes Provinces and the Pacific Northwest in the United States and Canada and in the province of Ontario in Canada Natural Gas Transmission also provides natural gas sales and distribution service to retail customers in Ontario, and natural gas gathering and processing services to customers in Western Canada Natural Gas Transmission does business primarily through Duke Energy Gas Transmission, LLC (DEGT) DEGT's natural gas transmission and storage operations in the U S are primarily subject to the FERC's and the U S Department of Transportation's (DOT's) rules and regulations, while natural gas gathering, processing, transmission, distribution and storage operations in Canada are primarily subject to the rules and regulations of the National Energy Board (NEB) and the Ontario Energy Board (OEB) As discussed below, effective January 2, 2007, Duke Energy consummated its spin-off of the natural gas businesses (Spectra Energy Corp (Spectra Energy)), which includes the Natural Gas Transmission business segment, to shareholders

Field Services includes Duke Energy's investment in DCP Midstream, LLC (formerly Duke Energy Field Services, LLC (DEFS)), which gathers, compresses, processes, transports, trades and markets, and stores natural gas DEFS also fractionates, transports, gathers, treats, processes, trades and markets, and stores natural gas liquids (NGLs) DEFS is 50% owned by ConocoPhillips and 50% owned by Duke Energy DEFS gathers raw natural gas through gathering systems located in major natural gas producing regions: Permian, Mid-Continent, East Texas-North Louisiana, South, Central, Rocky Mountain, and Gulf Coast As discussed below, effective January 2, 2007, Duke Energy consummated its spin-off of Spectra Energy, which includes Duke Energy's 50% ownership interest in DEFS, to shareholders

In July 2005, Duke Energy completed the agreement with ConocoPhillips, Duke Energy's co-equity owner in DEFS, to reduce Duke Energy's ownership interest in DEFS from 69 7% to 50% (the DEFS disposition transaction), which resulted in Duke Energy and ConocoPhillips becoming equal 50% owners in DEFS As a result of the DEFS disposition transaction, Duke Energy deconsolidated its investment in DEFS and subsequently has accounted for it as an investment utilizing the equity method of accounting

In June 2006, the Board of Directors of Duke Energy authorized management to pursue a plan to create two separate publicly traded companies by spinning off Duke Energy's natural gas businesses to Duke Energy shareholders On January 2, 2007, Duke Energy completed the spin-off of its natural gas businesses, including Duke Energy's 50% interest in DEFS, to shareholders The new natural gas business, which is named Spectra Energy, consists principally of the operations of Spectra Energy Capital LLC (Spectra Energy Capital, formerly Duke Capital LLC), excluding certain operations which were transferred from Spectra Energy Capital to Duke Energy in December 2006, primarily International Energy and Duke Energy's effective 50% interest in the Crescent JV The use of the term Spectra Energy Capital relates to operations of the former Duke Capital LLC or the post-spin Spectra Energy Capital, as the context requires Approximately $20 billion of assets, $13 billion of liabilities (which includes approximately $8 6 billion of debt issued by Spectra Energy Capital and its consolidated subsidiaries), and $7 billion of common stockholders' equity were distributed from Duke Energy as of the date of the spin-off Assets and liabilities of entities included in the spin-off of Spectra Energy were transferred from Duke Energy on a historical cost basis on the date of the spin-off transaction

The decision to spin off the natural gas businesses is expected to deliver long-term value to shareholders The historical results of the natural gas businesses are expected to be treated as discontinued operations at Duke Energy in future periods beginning with the first quarter of 2007 The primary businesses remaining in Duke Energy post-spin are principally the U S Franchised Electric and Gas business segment, the Commercial Power business segment, the International Energy business segment and Duke Energy's 50% interest in the Crescent JV (see below)

Commercial Power owns, operates and manages non-regulated merchant power plants and engages in the wholesale marketing and procurement of electric power, fuel and emission allowances related to these plants as well as other contractual positions Commercial Power also develops and implements customized energy solutions Commercial Power's generation asset fleet consists of Duke Energy Ohio's non-regulated generation in Ohio, acquired from Cinergy in April 2006, and the five Midwestern gas-fired merchant generation assets that were a portion of former DENA Commercial Power's assets comprise approximately 8,100 megawatts of power generation primarily located in the Midwestern United States The asset portfolio has a diversified fuel mix with base-load and mid-merit coal-fired units as well as combined cycle and peaking natural gas-fired units Most of the generation asset output in Ohio has been contracted through the Rate Stabilization Plan (RSP) For more information on the RSP, see "Commercial Power" section below

International Energy operates and manages power generation facilities, and engages in sales and marketing of electric power and natural gas outside the U S and Canada It conducts operations primarily through Duke Energy International, LLC (DEI) and its activities target power generation in Latin America Additionally, International Energy owns equity investments in Saudi Arabia, Mexico, and Greece

Crescent develops and manages high-quality commercial, residential and multi-family real estate projects primarily in the Southeastern and Southwestern United States Some of these projects are developed and managed through joint ventures Crescent also manages "legacy" land holdings in North and South Carolina

Table of Contents

PART I

On September 7, 2006, an indirect wholly owned subsidiary of Duke Energy closed an agreement to create a joint venture of Crescent (the Crescent JV) with Morgan Stanley Real Estate Fund V U S , L P (MSREF) and other affiliated funds controlled by Morgan Stanley (collectively the MS Members). Under the agreement, the Duke Energy subsidiary contributed all of the membership interests in Crescent to a newly-formed joint venture, which was ascribed an enterprise value of approximately $2 1 billion as of December 31, 2005 In conjunction with the formation of the Crescent JV, the joint venture, Crescent and Crescent's subsidiaries entered into a credit agreement with third party lenders under which Crescent borrowed approximately $1 21 billion, net of transaction costs, of which approximately $1 19 billion was immediately distributed to Duke Energy Immediately following the debt transaction, the MS Members collectively acquired a 49% membership interest in the Crescent JV from Duke Energy for a purchase price of approximately $415 million A 2% interest in the Crescent JV was also issued by the joint venture to the President and Chief Executive Officer of Crescent which is subject to forfeiture if the executive voluntarily leaves the employment of the Crescent JV within a three year period Additionally, this 2% interest can be put back to the Crescent JV after three years or possibly earlier upon the occurrence of certain events at an amount equal to 2% of the fair value of the Crescent JV's equity as of the put date Therefore, the Crescent JV will accrue the obligation related to the put as a liability over the three year forfeiture period Accordingly, Duke Energy has an effective 50% ownership in the equity of Crescent JV for financial reporting purposes Duke Energy's investment in the Crescent JV has been accounted for as an equity method investment for periods after September 7, 2006

The remainder of Duke Energy's operations is presented as "Other" While it is not considered a business segment, Other primarily includes the following:

- The remaining portion of Duke Energy's business formerly known as DENA, including its 100% owned affiliates Duke Energy Marketing America, LLC and Duke Energy Marketing Canada Corp Duke Energy also participates in Duke Energy Trading and Marketing, LLC (DETM) DETM is 40% owned by ExxonMobil Corporation and 60% owned by Duke Energy During the third quarter of 2005, Duke Energy's Board of Directors authorized and directed management to execute the sale or disposition of substantially all of former DENA's remaining assets and contracts outside the Midwestern United States and certain contractual positions related to the Midwestern assets The exit plan was completed in the second quarter of 2006 (see Note 13 to the Consolidated Financial Statements, "Discontinued Operations and Assets Held for Sale") In addition, management will continue to wind down the limited remaining operations of DETM. The results of operations for most of former DENA's businesses which Duke Energy has exited have been reflected as discontinued operations in the accompanying Consolidated Statements of Operations for all years presented
- Certain unallocated corporate costs, certain discontinued hedges, DukeNet Communications, LLC (DukeNet), Bison Insurance Company Limited (Bison), Duke Energy's wholly owned, captive insurance subsidiary, Cinergy's equity financing business and Duke Energy's 50% interest in Duke/Fluor Daniel (D/FD) DukeNet develops, owns and operates a fiber optic communications network, primarily in the Carolinas, serving wireless, local and long-distance communications companies, internet service providers and other businesses and organizations Bison's principal activities, as a captive insurance entity, include the insurance and reinsurance of various business risks and losses, such as workers compensation, property, business interruption and general liability of subsidiaries and affiliates of Duke Energy Bison also participates in reinsurance activities with certain third parties, on a limited basis Cinergy has a business which invests in start up businesses utilizing new energy technologies as well as technologies utilizing energy infrastructure, such as broadband over power line services D/FD is a 50/50 partnership between subsidiaries of Duke Energy and Fluor Corporation (Fluor) During 2003, Duke Energy and Fluor announced that they would dissolve D/FD and adopted a plan for an orderly wind-down of D/FD's business The wind-down has been substantially completed as of December 31, 2006 Previously, D/FD provided comprehensive engineering, procurement, construction, commissioning and operating plant services for fossil-fueled electric power generating facilities worldwide

Duke Energy is a Delaware corporation Its principal executive offices are located at 526 South Church Street, Charlotte, North Carolina 28202-1803 The telephone number is 704-594-6200. Duke Energy electronically files reports with the Securities and Exchange Commission (SEC), including annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, proxies and amendments to such reports The public may read and copy any materials that Duke Energy files with the SEC at the SEC's Public Reference Room at 100 F Street, N E , Washington, D C 20549 The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330 The SEC also maintains an internet site that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC at *http://www.sec.gov* Additionally, information about Duke Energy, including its reports filed with the SEC, is available through Duke Energy's web site at *http://www.duke-energy.com* Such reports are accessible at no charge through Duke Energy's web site and are made available as soon as reasonably practicable after such material is filed with or furnished to the SEC

Table of Contents

PART I

Terms used to describe Duke Energy's business are defined below

Accrual Model of Accounting (Accrual Model). An accounting term used by Duke Energy to refer to contracts for which there is generally no recognition in the Consolidated Statements of Operations for any changes in fair value until the service is provided, the associated delivery period occurs or there is hedge ineffectiveness As discussed further in Note 1 to the Consolidated Financial Statements, "Summary of Significant Accounting Policies," this term is applied to derivative contracts that are accounted for as cash flow hedges, fair value hedges, and normal purchases or sales, as well as to non-derivative contracts used for commodity risk management purposes As this term is not explicitly defined within U S Generally Accepted Accounting Principles (GAAP), Duke Energy's application of this term could differ from that of other companies

Allowance for Funds Used During Construction (AFUDC). An accounting convention of regulators that represents the estimated composite interest costs of debt and a return on equity funds used to finance construction The allowance is capitalized in the property accounts and included in income

British Thermal Unit (Btu). A standard unit for measuring thermal energy or heat commonly used as a gauge for the energy content of natural gas and other fuels

Cubic Foot (cf). The most common unit of measurement of gas volume; the amount of natural gas required to fill a volume of one cubic foot under stated conditions of temperature, pressure and water vapor

Decommissioning. The process of closing down a nuclear facility and reducing the residual radioactivity to a level that permits the release of the property and termination of the license Nuclear power plants are required by the Nuclear Regulatory Commission (NRC) to set aside funds for their decommissioning costs during operation.

Derivative. A financial instrument or contract in which its price is based on the value of underlying securities, equity indices, debt instruments, commodities or other benchmarks or variables. Often used to hedge risk, derivatives involve the trading of rights or obligations, but not the direct transfer of property Gains or losses on derivatives are often settled on a net basis

Distribution. The system of lines, transformers, switches and mains that connect electric and natural gas transmission systems to customers

Energy Marketing. Identification and execution of physical energy related transactions, generally with customized provisions to meet the needs of the customer or supplier, throughout the supply chain

Environmental Protection Agency (EPA). The U S agency that is responsible for researching and setting national standards for a variety of environmental programs, and delegates to states the responsibility for issuing permits and for monitoring and enforcing compliance

Federal Energy Regulatory Commission (FERC). The U S agency that regulates the transportation of electricity and natural gas in interstate commerce and authorizes the buying and selling of energy commodities at market-based rates

Forward Contract. A contract in which the buyer is obligated to take delivery, and the seller is obligated to deliver a specified amount of a commodity with a predetermined price formula on a specified future date, at which time payment is due in full

Fractionation/Fractionate. The process of separating liquid hydrocarbons from natural gas into propane, butane, ethane and other related products

Futures Contract. A contract, usually exchange traded, in which the buyer is obligated to take delivery and the seller is obligated to deliver a fixed amount of a commodity at a predetermined price on a specified future date

Gathering System. Pipeline, processing and related facilities that access production and other sources of natural gas supplies for delivery to mainline transmission systems

Generation. The process of transforming other forms of energy, such as nuclear or fossil fuels, into electricity. Also, the amount of electric energy produced, expressed in gigawatt-hours

Independent System Operator (ISO). An entity that acts as the transmission provider for a regional transmission system, providing customers access to the system and clearing all bi-lateral contract requests for use of the electric transmission system An ISO also shares responsibility for maintaining bulk electric system reliability

Integrated Resource Planning. The process typically utilized by regulated utilities in conjunction with state regulatory bodies for forecasting and planning the need for generation and transmission facilities

Light-off Fuel. Fuel oil used to light the coal prior to generating electricity

Liquefied Natural Gas (LNG). Natural gas that has been converted to a liquid by cooling it to minus 260 degrees Fahrenheit

Table of Contents

PART I

Liquidity. The ease with which assets or products can be traded without dramatically altering the current market price.

Local Distribution Company (LDC). A company that obtains the major portion of its revenues from the operations of a retail distribution system for the delivery of electricity or gas for ultimate consumption.

Mark-to-Market Model of Accounting (MTM Model). An accounting term used by Duke Energy to refer to derivative contracts for which an asset or liability is recognized at fair value and the change in the fair value of that asset or liability is recognized in the Consolidated Statements of Operations. As discussed further in Note 1 to the Consolidated Financial Statements, "Summary of Significant Accounting Policies," this term is applied to trading and undesignated non-trading derivative contracts. As this term is not explicitly defined within GAAP, Duke Energy's application of this term could differ from that of other companies.

Natural Gas. A naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in porous geological formations beneath the earth's surface, often in association with petroleum. The principal constituent is methane.

Natural Gas Liquids (NGLs). Liquid hydrocarbons extracted during the processing of natural gas. Principal commercial NGLs include butanes, propane, natural gasoline and ethane.

No-notice Bundled Service. A pipeline delivery service which allows customers to receive or deliver gas on demand without making prior nominations to meet service needs and without paying daily balancing and scheduling penalties.

Novation. The substitution of a new obligation or contract for an old one by the mutual agreement of all parties concerned.

Nuclear Regulatory Commission (NRC). The U.S. agency responsible for regulating the Nation's civilian use of byproduct, source, and special nuclear materials to ensure adequate protection of public health and safety, to promote the common defense and security, and to protect the environment. The NRC's scope of responsibility includes regulation of: commercial nuclear power reactors, including nonpower research, test and training reactors; fuel cycle facilities, including medical, academic and industrial uses of nuclear materials; and the transport, storage and disposal of nuclear materials and waste.

Origination. Identification and execution of physical energy related transactions, generally with customized provisions to meet the needs of the customer or supplier, throughout the supply chain.

Option. A contract that gives the buyer a right but not the obligation to purchase or sell an underlying asset at a specified price at a specified time.

Peak Load. The amount of electricity required during periods of highest demand. Peak periods fluctuate by season, generally occurring in the morning hours in winter and in late afternoon during the summer.

Portfolio. A collection of assets, liabilities, transactions, or trades.

Regional Transmission Organization (RTO). An independent entity which is established to have "functional control" over utilities' transmission systems, in order to expedite transmission of electricity. RTO's typically operate markets within their territories.

Reliability Must Run. Generation that an ISO determines is required to be on-line to meet applicable reliability criteria requirements.

Residue Gas. Gas remaining after the processing of natural gas.

Spark Spread. The difference between the value of electricity and the value of the gas required to generate the electricity at a specified heat rate.

Swap. A contract to exchange cash flows in the future according to a prearranged formula.

Throughput. The amount of natural gas or NGLs transported through a pipeline system.

Tolling. Arrangement whereby a buyer provides fuel to a power generator and receives generated power in return for a specified fee.

Transmission System (Electric). An interconnected group of electric transmission lines and related equipment for moving or transferring electric energy in bulk between points of supply and points at which it is transformed for delivery over a distribution system to customers, or for delivery to other electric transmission systems.

Transmission System (Natural Gas). An interconnected group of natural gas pipelines and associated facilities for transporting natural gas in bulk between points of supply and delivery points to industrial customers, LDCs, or for delivery to other natural gas transmission systems.

Volatility. An annualized measure of the fluctuation in the price of an energy contract.

Watt. A measure of power production or usage equal to one joule per second.

Table of Contents

PART I

The following sections describe the business and operations of each of Duke Energy's business segments (For more information on the operating outlook of Duke Energy and its segments, see "Management's Discussion and Analysis of Financial Condition and Results of Operations, Introduction—Executive Overview and Economic Factors for Duke Energy's Business" For financial information on Duke Energy's business segments, see Note 3 to the Consolidated Financial Statements, "Business Segments ")

U.S FRANCHISED ELECTRIC AND GAS

Service Area and Customers

U S Franchised Electric and Gas generates, transmits, distributes and sells electricity U S Franchised Electric and Gas also transports and sells natural gas It conducts operations primarily through Duke Energy Carolinas, Duke Energy Ohio, Duke Energy Indiana and Duke Energy Kentucky (Duke Energy Ohio, Duke Energy Indiana and Duke Energy Kentucky collectively referred to as Duke Energy Midwest). Its service area covers about 47,000 square miles with an estimated population of 10 million in central and western North Carolina, western South Carolina, southwestern Ohio, central and southern Indiana, and northern Kentucky U S Franchised Electric and Gas supplies electric service to approximately 3 9 million residential, commercial and industrial customers over 146,700 miles of distribution lines and a 20,700-mile transmission system U S Franchised Electric and Gas provides domestic regulated transmission and distribution services for natural gas to approximately 500,000 customers via approximately 8,900 miles of gas mains (gas distribution lines that serve as a common source of supply for more than one service line) and service lines Electricity is also sold wholesale to incorporated municipalities and to public and private utilities In addition, municipal and cooperative customers who purchased portions of the Catawba Nuclear Station may also buy power from a variety of suppliers including Duke Energy Carolinas, through contractual agreements (For more information on the Catawba Nuclear Station joint ownership, see Note 5 to the Consolidated Financial Statements, "Joint Ownership of Generating and Transmission Facilities ")

Duke Energy Carolinas' service area has a diversified commercial and industrial presence Manufacturing continues to be the largest contributor to the Carolinas' economy Other sectors such as information, financial and real estate services are growing

The textile industry, rubber and plastic products, chemicals and computer products are the most significant contributors to the area's manufacturing output and Duke Energy Carolinas' industrial sales revenue for 2006 Motor vehicle parts, building materials and electrical & electronic equipment manufacturing also have a strong impact in the area's economic growth and the region's industrial sales The textile industry, while in decline, is the largest industry served in the Carolinas

Duke Energy Carolinas has business development strategies to leverage the competitive advantages of North Carolina and South Carolina to attract and expand advanced manufacturing business in the region's service territory These competitive advantages, including a quality workforce, strong educational institutions and superior transportation infrastructure, were key factors in bringing in new customers in the plastics, pharmaceuticals, building materials and data processing industries The success in attracting new companies as well as expanding the operations of existing customers substantially offsets the sales declines in the textile and furniture industries in 2006

Industries of major economic significance in Duke Energy Indiana's service territory include chemicals, primary metals, and transportation Other significant industries operating in the area include stone, clay and glass, food products, paper, and other manufacturing Key sectors among commercial customers include education and retail trade

Duke Energy Indiana's business development strategies leveraged the competitive advantages of Indiana to attract new advanced manufacturing, logistics, life sciences and data center business to Duke Energy Indiana's service territory These advantages, including competitive electric rates, a strong transportation network, excellent institutions of higher learning, and a quality workforce, were key in attracting new customers and encouraging existing customer expansions This ability to attract business investment in the service territory helped balance the slight decline in sales in the chemical, food and transportation equipment sector

Duke Energy Ohio and Duke Energy Kentucky's service area has a diversified commercial and industrial presence Major components of the economy include manufacturing, real estate & rental leasing, wholesale trade, financial and insurance services, retail trade, education, healthcare and professional/business services Cincinnati is positioned to become a healthcare hub and the presence of non-durable manufacturing makes the area less vulnerable to economic fluctuations than other areas

The primary metals industry, transportation equipment, chemicals, and paper and plastics are the most significant contributors to the area's manufacturing output and Duke Energy Ohio and Duke Energy Kentucky's industrial sales revenue for 2006 Food, beverage and tobacco, fabricated metals, and electronics also have a strong impact on the area's economic growth and the region's industrial sales

Table of Contents

PART I

Duke Energy Ohio and Duke Energy Kentucky have business development strategies to leverage the competitive advantages of the Greater Cincinnati Region to attract and expand advanced manufacturing businesses The availability of a highly skilled workforce, superior highway access, low cost of living, and proximity to markets and raw materials were key factors in attracting new customers in the transportation, food manufacturing, chemical manufacturing, plastics and data processing industries

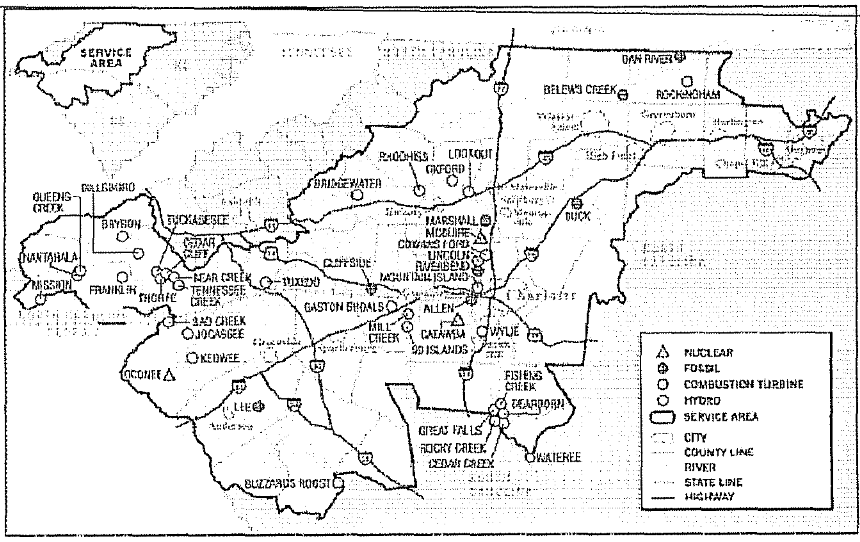
The number of residential and commercial customers within the U S Franchised Electric and Gas' service territory continues to increase Sales to these customers are increasing due to the growth in these sectors As sales to residential and commercial customers increase, the consistent level of sales to industrial customers becomes a smaller, yet still significant, portion of U S Franchised Electric and Gas sales

U S Franchised Electric and Gas' costs and revenues are influenced by seasonal patterns Peak sales occur during the summer and winter months, resulting in higher revenue and cash flows during those periods By contrast, fewer sales occur during the spring and fall allowing for scheduled plant maintenance during those periods

The following maps show the U S Franchised Electric and Gas' service territories and operating facilities

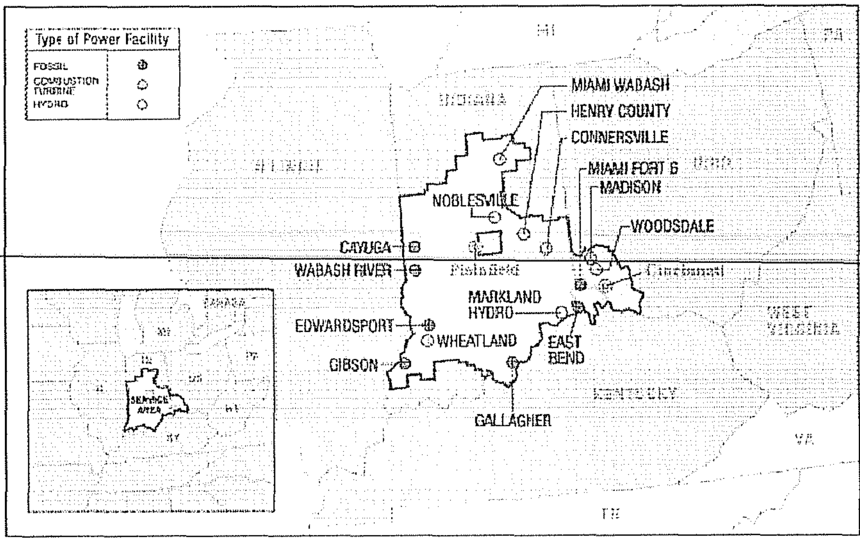
Duke Energy – Carolinas

Power Generation Regulated Facilities



PART I

Duke Energy – Midwest Power Generation
Regulated Facilities



Energy Capacity and Resources

Electric energy for U S. Franchised Electric and Gas' customers is generated by three nuclear generating stations with a combined net capacity of 5,020 megawatts (MW) (including Duke Energy's 12 5% ownership in the Catawba Nuclear Station), fifteen coal-fired stations with a combined net capacity of 13,552 MW, thirty-one hydroelectric stations (including two pumped-storage facilities) with a combined net capacity of 3,213 MW, fifteen combustion turbine (CT) stations burning natural gas, oil or other fuels with a combined net capacity of 5,245 MW and two combined cycle (CC) stations burning natural gas or synthetic gas with a combined net capacity of 560 MW The CT stations include the 2006 acquisition of the Rockingham CT facility (825 MW) from Dynegy Power Marketing, Inc The acquisition was completed November 10, 2006 and was the most recent addition to U S Franchised Electric and Gas' resource capability Energy and capacity are also supplied through contracts with other generators and purchased on the open market Factors that could cause U S Franchised Electric and Gas to purchase power for its customers include generating plant outages, extreme weather conditions, summer reliability, growth, and price U S Franchised Electric and Gas has interconnections and arrangements with its neighboring utilities to facilitate planning, emergency assistance, sale and purchase of capacity and energy, and reliability of power supply

In December 2006, Duke Energy announced an agreement to purchase a portion of Saluda River Electric Cooperative, Inc 's ownership interest in the Catawba Nuclear Station Under the terms of the agreement, Duke Energy will pay approximately $158 million for the additional ownership interest of the Catawba Nuclear Station Following the closing of the transaction, Duke Energy will own approximately 19 percent of Catawba Nuclear Station This transaction, which is expected to close prior to September 30, 2008, is subject to approval by various state and federal agencies

U S Franchised Electric and Gas' generation portfolio is a balanced mix of energy resources having different operating characteristics and fuel sources designed to provide energy at the lowest possible cost to meet its obligation to serve native-load customers All options including owned generation resources and purchased power opportunities are continually evaluated on a real-time basis to select and dispatch the lowest-cost resources available to meet system load requirements The vast majority of customer energy needs are met by large, low-energy-production-cost nuclear and coal-fired generating units that operate almost continuously (or at baseload levels) In 2006, approximately 98 8% of the total generated energy came from U S Franchised Electric and Gas' low-cost, efficient nuclear and coal units (51 9% coal and 46 9% nuclear) The remaining energy needs were supplied by hydroelectric, CT and CC generation or economical purchases from the wholesale market

Hydroelectric (both conventional and pumped storage) in the Carolinas and gas/oil CT and CC stations in both the Carolinas and Midwest operate primarily during the peak-hour load periods (at peaking levels) when customer loads are rapidly changing CT's and CC's produce energy at higher production costs than either nuclear or coal, but are less expensive to build and maintain, and can be rapidly started or stopped as needed to meet changing customer loads Hydroelectric units produce low-cost energy, but their operations are limited by the availability of water flow

U S Franchised Electric and Gas' major pumped-storage hydroelectric facilities offer the added flexibility of using low-cost off-peak energy to pump water that will be stored for later generation use during times of higher-cost on-peak generation periods These facilities allow U S Franchised Electric and Gas to maximize the value spreads between different high- and low-cost generation periods

U S Franchised Electric and Gas is engaged in planning efforts to meet projected load growth in its service territory Long-term projections indicate a need for significant capacity additions, which may include new nuclear, coal and integrated gasification combined cycle (IGCC) facilities Because of the long lead times required to develop such assets, U S Franchised Electric and Gas is taking steps now to ensure those options are available For example, Duke Energy Carolinas filed an application with the NCUC for a Certificate of Public Convenience and Necessity (CPCN) on June 2, 2006 for regulatory approval to build the Cliffside Project consisting of two 800 MW supercritical coal units at the existing Cliffside Steam Station, located in Rutherford and Cleveland Counties of North Carolina. Steps are also being taken to maintain the option to bring the Cliffside project on-line as early as 2011. On February 28, 2007, the NCUC issued a notice of decision approving the construction of one unit at the Cliffside Steam Station The NCUC stated that it will issue a full order in the near future Duke Energy will review the NCUC's order, once issued, and determine whether to proceed with the Cliffside Project or consider other alternatives, including additional gas fired generation In September 2006, Duke Energy Indiana and Vectren Energy Delivery of Indiana, Inc filed a joint petition with the IURC seeking a CPCN for constructing a 630 MW IGCC power plant at Duke Energy Indiana's Edwardsport Generating Station in Knox County, Indiana In addition, Duke Energy Carolinas is preparing an application for a Combined Construction and Operating License from the NRC, with the objective of potentially bringing a new nuclear facility on line by 2016 Although U S Franchised Electric and Gas is progressing with these efforts, final decisions regarding the development of new power facilities will be driven by realized demand, market conditions and other strategic considerations

In evaluating the construction of several large, new electric generating plants in North Carolina, South Carolina, and Indiana, Duke Energy has begun to see significant increases in the estimated costs of these projects driven by strong domestic and international demand for the material, equipment and labor necessary to construct these facilities In October 2006, Duke Energy made a filing with the NCUC related to the Duke Energy Carolinas' request for a CPCN for the Cliffside project In this filing, Duke Energy stated that due to the rising costs described above, the cost of building the Cliffside units could be approximately $3 billion, excluding allowance for funds used during construction (AFUDC) The costs described above are expected to continue to increase causing the overall cost of the Cliffside project to increase, until such time as the NCUC issues a CPCN and Duke Energy is able to enter into definitive agreements with necessary material and service providers In November 2006, Duke Energy received approval for nearly $260 million of future federal tax credits related to costs to be incurred for the modernization of the Cliffside facility as well as the IGCC plant in Indiana

Duke Energy Indiana's estimated costs associated with the potential construction of an IGCC plant in Indiana have also increased Duke Energy Indiana's publicly filed testimony with the IURC on October 24, 2006 indicates that industry (Electric Power Research Institute) estimates of total capital requirement for a facility of this type and size are now in the range of $1 6 billion to $2 1 billion (including escalation to 2011 and owner's specific site costs)

Fuel Supply

U S Franchised Electric and Gas relies principally on coal and nuclear fuel for its generation of electric energy The following table lists U S Franchised Electric and Gas' sources of power and fuel costs for the three years ended December 31, 2006

	Generation by Source (Percent)			Cost of Delivered Fuel per Net Kilowatt-hour Generated (Cents)		
	2006	2005 (d)	2004 (d)	2006	2005 (d)	2004 (d)
Coal	63 4	52 5	52 2	2.16	2.14	1.84
Nuclear(a)	35 1	45 7	45 9	0 42	0 41	0 41
Oil and gas(b)	0.6	0.1	0.2	12.67	28 83	16.79
All fuels (cost based on weighted average)(a)	99 1	98 3	98 3	1 61	1 36	1.20
Hydroelectric(c)	0 9	1 7	1 7			
	100 0	100 0	100 0			

PART I

(a) Statistics related to nuclear generation and all fuels reflect U S Franchised Electric and Gas' 12.5% ownership interest in the Catawba Nuclear Station
(b) Cost statistics include amounts for light-off fuel at U S Franchised Electric and Gas' coal-fired stations
(c) Generating figures are net of output required to replenish pumped storage facilities during off-peak periods
(d) Excludes the Midwest

Coal U S Franchised Electric and Gas meets its coal demand in the Carolinas and Midwest through a portfolio of purchase supply contracts and spot agreements Large amounts of coal are purchased under supply contracts with mining operators who mine both underground and at the surface U S Franchised Electric and Gas uses spot-market purchases to meet coal requirements not met by supply contracts Expiration dates for its supply contracts, which have various price adjustment provisions and market re-openers, range from 2007 to 2016. U S Franchised Electric and Gas expects to renew these contracts or enter into similar contracts with other suppliers for the quantities and quality of coal required as existing contracts expire, though prices will fluctuate over time as coal markets change The coal purchased for the Carolinas is primarily produced from mines in eastern Kentucky, West Virginia and southwestern Virginia The coal purchased for the Midwest is primarily produced in Indiana, Illinois, and Kentucky U S Franchised Electric and Gas has an adequate supply of coal to fuel its current and projected operations

The current average sulfur content of coal purchased by U.S. Franchised Electric and Gas for the Carolinas is approximately 1%, however, as several Carolinas coal plants bring on scrubbers over the next several years the sulfur content of coal purchased could increase as higher sulfur coal options are considered The current average sulfur content of coal purchased by U S Franchised Electric and Gas for the Midwest is approximately 2% Coupled with the use of available sulfur dioxide emission allowances on the open market, this satisfies the current emission limitations for sulfur dioxide for existing facilities in the Carolinas and Midwest

Gas U S Franchised Electric and Gas is responsible for the purchase and the subsequent delivery of natural gas to native load customers in the Midwest U S Franchised Electric and Gas' natural gas procurement strategy is to buy firm natural gas supplies (natural gas intended to be available at all times) and firm interstate pipeline transportation capacity during the winter season (November through March) and during the non-heating season (April through October) through a combination of firm supply and transportation capacity along with spot supply and interruptible transportation capacity This strategy allows U S Franchised Electric and Gas to assure reliable natural gas supply for its high priority (non-curtailable) firm customers during peak winter conditions and provides U S Franchised Electric and Gas the flexibility to reduce its contract commitments if firm customers choose alternate gas suppliers under U S Franchised Electric and Gas' customer choice/gas transportation programs In 2006, firm supply purchase commitment agreements provided approximately 91% of the natural gas supply, with the remaining gas purchased on the spot market These firm supply agreements feature two levels of gas supply, specifically (1) baseload, which is a continuous supply to meet normal demand requirements, and (2) swing load, which is gas available on a daily basis to accommodate changes in demand due primarily to changing weather conditions

U S Franchised Electric and Gas manages natural gas procurement-price volatility mitigation programs for Duke Energy Ohio and Duke Energy Kentucky These programs pre-arrange between 25-75% of winter heating season baseload gas requirements and up to 25-50% of summer season baseload requirements up to three years in advance of the delivery month Duke Energy Ohio and Duke Energy Kentucky use primarily fixed-price forward contracts and contracts with a ceiling and floor on the price As of December 31, 2006, Duke Energy Ohio and Duke Energy Kentucky, combined, had hedged approximately 73% of their winter 2006/2007 base load requirements

Nuclear. Developing nuclear generating fuel generally involves the mining and milling of uranium ore to produce uranium concentrates, the conversion of uranium concentrates to uranium hexafluoride gas, enrichment of that gas, and then the fabrication of the enriched uranium hexafluoride into usable fuel assemblies

U S Franchised Electric and Gas has contracted for uranium materials and services required to fuel the Oconee, McGuire and Catawba Nuclear Stations in the Carolinas Uranium concentrates, conversion services and enrichment services are primarily met through a diversified portfolio of long-term supply contracts The contracts are diversified by supplier, country of origin and pricing U S Franchised Electric and Gas staggers its contracting so that its portfolio of long-term contracts covers the majority of its fuel requirements at Oconee, McGuire and Catawba in the near term, but so that its level of coverage decreases over time into the future Due to the technical complexities of changing suppliers of fuel fabrication services, U S Franchised Electric and Gas generally sole sources these services to a single domestic supplier on a plant-by-plant basis using multi-year contracts

Based on current projections, U S Franchised Electric and Gas' existing portfolio of contracts will meet the requirements of Oconee, McGuire and Catawba Nuclear Stations through the following years:

Nuclear Station	Uranium Material	Conversion Service	Enrichment Service	Fabrication Service
Oconee	2011	2011	2009	2015
McGuire	2011	2011	2009	2015
Catawba	2011	2011	2009	2014

After the years indicated above, a portion of the fuel requirements at Oconee, McGuire and Catawba are covered by long-term contracts For requirements not covered under long-term contracts, Duke Energy believes it will be able to renew contracts as they expire, or enter into similar contractual arrangements with other suppliers of nuclear fuel materials and services Near-term requirements not met by long-term supply contracts have been and are expected to be fulfilled with uranium spot market purchases

Duke Energy Carolinas has entered into a contract with Shaw AREVA MOX Services (MOX Services) (formerly Duke COGEMA Stone & Webster, LLC (DCS)) under which Duke Energy Carolinas has agreed to prepare the McGuire and Catawba nuclear reactors for use of mixed-oxide fuel and to purchase mixed-oxide fuel for use in such reactors. Mixed-oxide fuel will be fabricated by MOX Services from the U S government's excess plutonium from its nuclear weapons programs and is similar to conventional uranium fuel Before using the fuel, Duke Energy Carolinas must apply for and obtain amendments to the facilities' operating licenses from the NRC On March 3, 2005, the NRC issued amendments to Catawba Nuclear Station's operating licenses to allow the receipt and use of four mixed oxide fuel lead assemblies These four lead assemblies completed their first cycle of irradiation on November 11, 2006 and have been inserted for a second cycle of irradiation in Unit 1 of the Catawba Nuclear Station

Inventory

Generation of electricity is capital-intensive U S Franchised Electric and Gas must maintain an adequate stock of fuel, materials and supplies in order to ensure continuous operation of generating facilities and reliable delivery to customers As of December 31, 2006, the inventory balance for U S Franchised Electric and Gas was approximately $795 million. (See Note 1 to the Consolidated Financial Statements, "Summary of Significant Accounting Policies," for additional information)

Insurance and Decommissioning

Duke Energy owns and operates the McGuire and Oconee Nuclear Stations and operates and has a partial ownership interest in the Catawba Nuclear Station The McGuire and the Catawba Nuclear Stations have two nuclear reactors each and Oconee has three Nuclear insurance includes liability coverage, property, decontamination and premature decommissioning coverage; and business interruption and/or extra expense coverage The other joint owners of the Catawba Nuclear Station reimburse Duke Energy for certain expenses associated with nuclear insurance premiums The Price-Anderson Act requires Duke Energy to insure against public liability claims resulting from nuclear incidents to the full limit of liability, approximately $10 8 billion (See Note 17 to the Consolidated Financial Statements, "Commitments and Contingencies—Nuclear Insurance," for more information)

In 2005, the NCUC and PSCSC approved a $48 million annual amount for contributions and expense levels for decommissioning During 2006, Duke Energy expensed approximately $48 million and contributed approximately $48 million of cash to the Nuclear Decommissioning Trust Funds (NDTF) for decommissioning costs; these amounts are presented in the Consolidated Statements of Cash Flows in Purchases of available-for-sale securities within Cash Flows from Investing Activities The $48 million was contributed entirely to the funds reserved for contaminated costs Contributions were discontinued to the funds reserved for non-contaminated costs since the current estimates indicate existing funds to be sufficient to cover projected future costs The balance of the external funds was $1,775 million as of December 31, 2006 and $1,504 million as of December 31, 2005 These amounts are reflected in the Consolidated Balance Sheets as Nuclear Decommissioning Trust Funds (asset).

Estimated site-specific nuclear decommissioning costs, including the cost of decommissioning plant components not subject to radioactive contamination, total approximately $2 3 billion in 2003 dollars, based on a decommissioning study completed in 2004 This includes costs related to Duke Energy's 12 5% ownership in Catawba Nuclear Station The other joint owners of Catawba Nuclear Station are responsible for decommissioning costs related to their ownership interests in the station. The previous study, conducted in 1999, estimated a decommissioning cost of $1 9 billion ($2 2 billion in 2003 dollars at 3% inflation). The estimated increase is due primarily to inflation and cost increases for the size of the organization needed to manage the decommissioning project (based on current industry experience at facilities undergoing decommissioning). Both the NCUC and the PSCSC have allowed Duke Energy to recover estimated decommissioning costs through retail rates over the expected remaining service periods of Duke Energy's nuclear stations Management believes that the decommissioning costs being recovered through rates, when coupled with expected fund earnings, are sufficient to provide for the cost of decommissioning

After spent fuel is removed from a nuclear reactor, it is cooled in a spent-fuel pool at the nuclear station Under provisions of the Nuclear Waste Policy Act of 1982, Duke Energy contracted with the U S Department of Energy (DOE) for the disposal of spent nuclear fuel The DOE failed to begin accepting spent nuclear fuel on January 31, 1998, the date specified by the Nuclear Waste Policy Act and in Duke Energy's contract with the DOE In 1998, Duke Energy filed a claim with the U S Court of Federal Claims against the DOE related to the DOE's failure to accept commercial spent nuclear fuel by the required date Damages claimed in the lawsuit are based upon Duke

Energy's costs incurred as a result of the DOE's partial material breach of its contract, including the cost of securing additional spent fuel storage capacity The matter has been stayed pending the result of ongoing settlement negotiations between Duke Energy and the DOE Duke Energy will continue to safely manage its spent nuclear fuel until the DOE accepts it Payments made to the DOE for expected future disposal costs are based on nuclear output and are included in the Consolidated Statements of Operations as Fuel used in electric generation and purchased power Duke Energy expects resolution of this matter in the first quarter of 2007

Duke Energy has experienced numerous claims relating to damages for personal injuries alleged to have arisen from the exposure to or use of asbestos in connection with construction and maintenance activities conducted by Duke Energy Carolinas on its electric generation plants during the 1960s and 1970s Duke Energy has third-party insurance to cover losses related to these asbestos-related injuries and damages above a certain aggregate deductible The insurance policy, including the policy deductible and reserves, provided for coverage to Duke Energy up to an aggregate of $1 6 billion when purchased in 2000 Probable insurance recoveries related to this policy are classified in the Consolidated Balance Sheets as Other within Investments and Other Assets Amounts recognized as reserves in the Consolidated Balance Sheets, which are not anticipated to exceed the coverage, are classified in Other Deferred Credits and Other Liabilities and Other Current Liabilities and are based upon Duke Energy's best estimate of the probable liability for future asbestos claims These reserves are based upon current estimates and are subject to uncertainty Factors such as the frequency and magnitude of future claims could change the current estimates of the related reserves and claims for recoveries reflected in the accompanying Consolidated Financial Statements However, management of Duke Energy does not currently anticipate that any changes to these estimates will have any material adverse effect on Duke Energy's consolidated results of operations, cash flows or financial position.

Competition

U S Franchised Electric and Gas competes in some areas with government-owned power systems, municipally owned electric systems, rural electric cooperatives and other private utilities By statute, the NCUC and the PSCSC assign service areas outside municipalities in North Carolina and South Carolina to regulated electric utilities and rural electric cooperatives Substantially all of the territory comprising Duke Energy Carolinas' service area has been assigned in this manner In unassigned areas, Duke Energy Carolinas' business remains subject to competition A decision of the North Carolina Supreme Court limits, in some instances, the right of North Carolina municipalities to serve customers outside their corporate limits In South Carolina, competition continues between municipalities and other electric suppliers outside the municipalities' corporate limits, subject to the regulation of the PSCSC In Kentucky, the right of municipalities to serve customers outside corporate limits is subject to court approval In Indiana, the state is divided into certified electric service areas for municipal utilities, rural cooperatives and investor owned utilities There are limited circumstances where the certified electric service areas can be modified, with approval of the IURC U S Franchised Electric and Gas also competes with other utilities and marketers in the wholesale electric business In addition, U S Franchised Electric and Gas continues to compete with natural gas providers

Duke Energy Ohio operates under the RSP Market Based Standard Service Offer (MBSSO) which was approved by the PUCO in November 2004, and which provides price certainty through December 31, 2008 In March 2005, the Office of the Ohio Consumers' Counsel (OCC) appealed the PUCO's approval of the MBSSO and in November 2006, the Ohio Supreme Court remanded the PUCO's order approving the MBSSO for further evidentiary support and explanation, and to require Duke Energy Ohio to disclose certain confidential commercial agreements between Duke Energy Ohio and other parties previously requested by the OCC Hearings on remand are expected to occur in March 2007 A major feature of the MBSSO is the Provider of Last Resort (POLR) Charge Duke Energy Ohio has been collecting a POLR charge from non-residential customers since January 1, 2005, and from residential customers since January 1, 2006 The POLR charge consists of the following discrete charges:

- Annually Adjusted Component - intended to provide cost recovery primarily for environmental compliance expenditures This component is avoidable (or by-passable) for the first 25% of residential load and 50% of non-residential load to switch to an alternative electric service provider
- Infrastructure Maintenance Fund Charge - intended to compensate Duke Energy Ohio for committing its physical capacity This charge is unavoidable (or non-by-passable)
- System Reliability Tracker - intended to provide actual cost recovery for capacity purchases, purchased power, reserve capacity, and related market costs for purchases to meet capacity needs This charge is non-by-passable for residential load and by-passable for non-residential load under certain circumstances
- Rate Stabilization Charge - intended to compensate Duke Energy Ohio for maintaining a fixed price through 2008 This charge is by-passable by the first 25% of residential load and 50% of non-residential load to switch

PART I

- Generation Prices and Fuel Recovery: A market price has been established for generation service A component of the market price is a fuel cost recovery mechanism that is adjusted quarterly for fuel, emission allowances, and certain purchased power costs, that exceed the amount originally included in the rates frozen in the Duke Energy Ohio transition plan These new prices were applied to non-residential customers beginning January 1, 2005 and to residential customers beginning January 1, 2006
- Transmission Cost Recovery: A transmission cost recovery mechanism was established beginning January 1, 2005 for non-residential customers and beginning January 1, 2006 for residential customers The transmission cost recovery mechanism is designed to permit Duke Energy Ohio to recover certain Midwest ISO charges, all FERC approved transmission costs, and all congestion costs allocable to retail ratepayers that are provided service by Duke Energy Ohio.

Regulation

State

The NCUC, the PSCSC, the PUCO, the IURC and the KPSC (collectively, the State Utility Commissions) approve rates for retail electric service within their respective states In addition, the PUCO and the KPSC approve rates for retail gas distribution service within their respective states The FERC approves U S Franchised Electric and Gas' cost based rates for electric sales to certain wholesale customers (For more information on rate matters, see Note 4 to the Consolidated Financial Statements, "Regulatory Matters—U S Franchised Electric and Gas ") The FERC and the State Utility Commissions, except for the PUCO, also have authority over the construction and operation of U S Franchised Electric and Gas' facilities Certificates of public convenience and necessity issued by the FERC and the State Utility Commissions, as applicable, authorize U S Franchised Electric and Gas to construct and operate its electric facilities, and to sell electricity to retail and wholesale customers Prior approval from the relevant State Utility Commission is required for Duke Energy's regulated operating companies to issue securities

Electric generation supply service has been deregulated in Ohio Accordingly, Duke Energy Ohio's electric generation has been deregulated, and Duke Energy Ohio is in a competitive retail electric service market in the state of Ohio Under applicable legislation governing the deregulation of generation, Duke Energy Ohio has implemented a RSP including a MBSSO approved by the PUCO The RSP, among other things, allows Duke Energy Ohio to recover increased costs associated with environmental expenditures on its deregulated generating fleet, capacity reserves, and provides for a fuel and emission allowance cost recovery mechanism through 2008 (see Note 4 to the Consolidated Financial Statements, "Regulatory Matters—U S Franchised Electric and Gas Rate Related Information" for additional information)

Federal

Regulations of FERC and the State Utility Commissions govern access to regulated electric and gas customer and other data by non-regulated entities, and services provided between regulated and non-regulated energy affiliates These regulations affect the activities of non-regulated affiliates with U S Franchised Electric and Gas

The Energy Policy Act of 2005 was signed into law in August 2005 The legislation directs specified agencies to conduct a significant number of studies on various aspects of the energy industry and to implement other provisions through rulemakings Among the key provisions, the Energy Policy Act of 2005 repeals the Public Utility Holding Company Act (PUHCA) of 1935, directs FERC to establish a self-regulating electric reliability organization governed by an independent board with FERC oversight, extends the Price Anderson Act for 20 years (until 2025), provides loan guarantees, standby support and production tax credits for new nuclear reactors, gives FERC enhanced merger approval authority, provides FERC new backstop authority for the siting of certain electric transmission projects, streamlines the processes for approval and permitting of interstate pipelines, and reforms hydropower relicensing In 2005 and 2006, FERC initiated several rulemakings as directed by the Energy Policy Act of 2005 These rule makings have now been completed, subject to certain appeals Duke Energy does not believe that the appeals of these rulemakings will have a material adverse effect on its consolidated results of operations, cash flows or financial position

The Energy Policy Act of 1992 and subsequent rulemakings and events initiated the opening of wholesale energy markets to competition Open access transmission for wholesale transmission provides energy suppliers and load serving entities, including U S Franchised Electric and Gas and wholesale customers located in the U S Franchised Electric and Gas service area, with opportunities to purchase, sell and deliver capacity and energy at market based prices, which can lower overall costs to retail customers

Duke Energy Ohio, Duke Energy Kentucky and Duke Energy Indiana are transmission owners in a regional transmission organization operated by the Midwest Independent Transmission System Operator, Inc (Midwest ISO), a non-profit organization which maintains functional control over the combined transmission systems of its members In 2005, the Midwest ISO began administering an energy market within its footprint

Table of Contents

As a result of previous FERC rulemakings related to RTOs, Duke Energy Carolinas and the franchised electric units of Carolina Power & Light Company (now Progress Energy Carolinas) and South Carolina Electric & Gas Company, planned to establish GridSouth Transco, LLC (GridSouth), as an RTO responsible for the functional control of the companies' combined transmission systems As of December 31, 2006, Duke Energy Carolinas had a net investment of $41 million in GridSouth, including carrying costs calculated through December 31, 2002 This amount is included in Other Regulatory Assets and Deferred Debits on the Consolidated Balance Sheets Due to regulatory uncertainty, development of the GridSouth implementation project was suspended in 2002 In 2005, the companies notified the FERC that they had discontinued the GridSouth project Management expects it will recover its investment in GridSouth

On December 17, 2001 the IURC approved the transfer of functional control of the operation of the Duke Energy Indiana transmission system to the Midwest ISO, an RTO established in 1998. On June 1, 2005, the IURC authorized Duke Energy Indiana to transfer control area operations tasks and responsibilities and transfer dispatch and Day 2 energy markets tasks and responsibilities to the Midwest ISO.

The Midwest ISO is the provider of transmission service requested on the transmission facilities under its tariff It is responsible for the reliable operation of those transmission facilities and the regional planning of new transmission facilities The Midwest ISO administers energy markets utilizing Locational Marginal Pricing (LMP) (i e , the energy price for the next MW may vary throughout the Midwest ISO market based on transmission congestion and energy losses) as the methodology for relieving congestion on the transmission facilities under its functional control

On December 19, 2005, the FERC approved a plan filed by Duke Energy Carolinas to establish an "Independent Entity" (IE) to serve as a coordinator of certain transmission functions and an "Independent Monitor" (IM) to monitor the transparency and fairness of the operation of Duke Energy Carolinas' transmission system Under the proposal, Duke Energy Carolinas will remain the owner and operator of the transmission system with responsibility for the provision of transmission service under Duke Energy Carolinas' Open Access Transmission Tariff Duke Energy Carolinas has retained the Midwest ISO to act as the IE and Potomac Economics, Ltd to act as the IM. The IE and IM began operations on November 1, 2006 Duke Energy Carolinas is not at this time seeking adjustments to its transmission rates to reflect the incremental cost of the proposal, which is not projected to have a material adverse effect on Duke Energy's future consolidated results of operations, cash flows or financial position

Other

U S Franchised Electric and Gas is subject to the NRC jurisdiction for the design, construction and operation of its nuclear generating facilities In 2000, the NRC renewed the operating license for Duke Energy's three Oconee nuclear units through 2033 and 2034 In 2003, the NRC renewed the operating licenses for all units at Duke Energy's McGuire and Catawba stations The two McGuire units are licensed through 2041 and 2043, while the two Catawba units are licensed through 2043 All but one of U S Franchised Electric and Gas' hydroelectric generating facilities are licensed by the FERC under Part I of the Federal Power Act, with license terms expiring from 2005 to 2036 The FERC has authority to issue new hydroelectric generating licenses Hydroelectric facilities whose licenses have expired in 2005 are operating under annual extensions of the current license until FERC issues a new license Other hydroelectric facilities whose licenses expire between 2008 and 2016 are in various stages of relicensing Duke Energy expects to receive new licenses for all hydroelectric facilities with the exception of the Dillsboro Project, for which Duke Energy has filed an application to surrender the license Duke Energy expects to remove this project's dam and powerhouse, as part of the multi-stakeholder licensing agreement

U S Franchised Electric and Gas is subject to the jurisdiction of the EPA and state and local environmental agencies (For a discussion of environmental regulation, see "Environmental Matters" in this section)

NATURAL GAS TRANSMISSION

As previously discussed, effective January 2, 2007, Duke Energy consummated its spin-off of the natural gas transmission businesses (Spectra Energy), which includes the Natural Gas Transmission segment, to shareholders The following business description of Natural Gas Transmission relates to 2006 and is not intended to describe the business subsequent to the spin-off on January 2, 2007

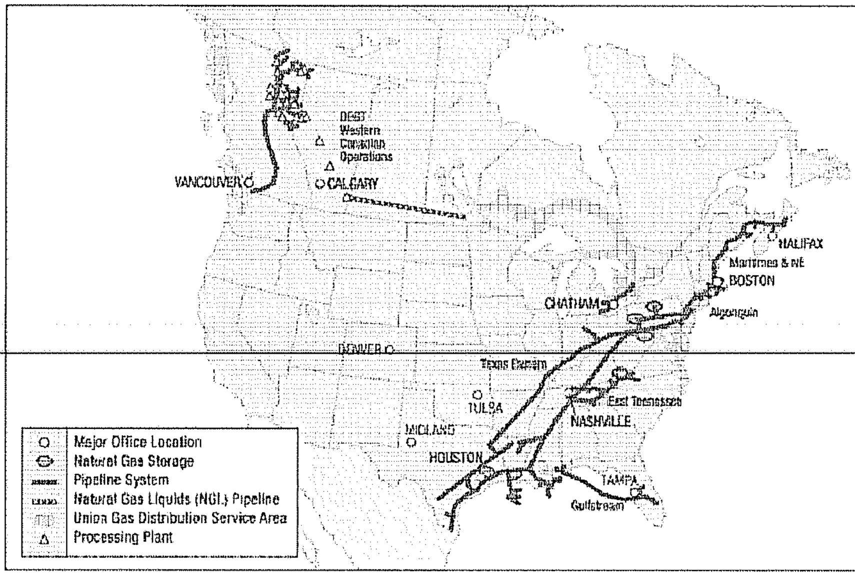
Natural Gas Transmission provides transportation and storage of natural gas for customers in various regions of the Eastern and Southeastern United States, the Maritimes Provinces and the Pacific Northwest in the United States and Canada and in the province of Ontario in Canada Natural Gas Transmission also provides natural gas sales and distribution service to retail customers in Ontario, and natural gas gathering and processing services to customers in Western Canada Natural Gas Transmission does business primarily through DEGT

Natural Gas Transmission's pipeline systems consist of more than 17,500 miles of transmission pipelines The pipeline systems receive natural gas from major North American producing regions for delivery to our markets For 2006, Natural Gas Transmission's proportional throughput for its pipelines totaled 3,248 trillion British thermal units (TBtu), compared to 3,410 TBtu in 2005 This includes throughput on Natural Gas Transmission's wholly owned U.S and Canadian pipelines and its proportional share of throughput on pipelines that are not wholly owned A majority of Natural Gas Transmission's contracted transportation volumes are under long-term firm service agreements with LDC customers in the pipelines' market areas Firm transportation services are also provided to gas marketers, producers, other pipelines, electric power generators and a variety of end-users, and both firm and interruptible transportation services are provided to various customers on a short-term or seasonal basis In the course of providing transportation services, Natural Gas Transmission also processes natural gas on its U S. system Demand on Natural Gas Transmission's pipeline systems is seasonal, with the highest throughput occurring during colder periods in the first and fourth calendar quarters (For detailed descriptions of Natural Gas Transmission's pipeline systems, see "Properties—Natural Gas Transmission")

Natural Gas Transmission, through Market Hub Partners (MHP), wholly owns natural gas salt cavern storage facilities in Southeast Texas and Louisiana MHP markets natural gas storage services to pipelines, LDCs, producers, end users and natural gas marketers Texas Eastern Transmission, L.P (Texas Eastern) and East Tennessee Natural Gas, LLC (ETNG), subsidiaries of Natural Gas Transmission, also provide firm and interruptible open-access storage services Storage is offered as a stand-alone unbundled service or as part of a no-notice bundled service with transportation. ETNG also connects to Saltville Gas Storage Company L.L.C and Early Grove Storage Company, subsidiaries of Natural Gas Transmission These underground reservoir and salt cavern storage facilities are located in Virginia and provide storage services to customers in the Southeastern United States.

Natural Gas Transmission provides retail distribution services through its subsidiary, Union Gas Limited (Union Gas). Union Gas owns and operates natural gas transmission, distribution and storage facilities in Ontario. Union Gas distributes natural gas to approximately 1.3 million residential, commercial and industrial customers in Northern, Southwestern and Eastern Ontario and provides storage, transportation and related services to utilities and other industry participants in the gas markets of Ontario, Quebec and the Central and Eastern United States

Natural Gas Transmission owns and operates gathering pipelines and gas processing plants in Western Canada through its British Columbia Pipeline System (BC Pipeline) operations and provides services primarily to natural gas producers to remove impurities from the raw gas stream including water, carbon dioxide, hydrogen sulphide and other substances. Where required, these facilities remove various NGLs Natural Gas Transmission's Empress system assets located in Western Canada provide extraction, storage, transportation, distribution and marketing of NGLs in Canada and the U S Natural Gas Transmission also provides gathering and processing services through its 46% interest in the Canadian Midstream operations in Western Canada that are owned by Spectra Energy Income Fund (Income Fund), formerly Duke Energy Income Fund Natural Gas Transmission continues to operate and manage this business



Competition

Natural Gas Transmission's transportation, storage and gas gathering and processing businesses compete with similar facilities that serve its supply and market areas in the transportation, storage, gathering and processing of natural gas The principal elements of competition are rates, terms of service, flexibility and reliability of service

Natural gas competes with other forms of energy available to Natural Gas Transmission's customers and end-users, including electricity, coal, propane and fuel oils Several factors influence the demand for natural gas including price changes, the availability of natural gas and other forms of energy, the level of business activity, conservation, legislation, governmental regulations, the ability to convert to alternative fuels, weather and other factors

Regulation

Most of Natural Gas Transmission's pipeline and storage operations in the U S are regulated by the FERC The FERC regulates natural gas transportation in U S interstate commerce including the establishment of rates for services (For more information on rate matters, see Note 4 to the Consolidated Financial Statements, "Regulatory Matters—Natural Gas Transmission ") The FERC also regulates the construction of U S interstate pipelines and storage facilities, including extension, enlargement or abandonment of such facilities In addition, certain operations are subject to oversight by state regulatory commissions.

FERC regulations restrict U S interstate pipelines from sharing transmission or customer information with energy affiliates and require that U S interstate pipelines function independently of their energy affiliates These regulations affect the activities of non-regulated affiliates with Natural Gas Transmission

The FERC may propose and implement new rules and regulations affecting interstate natural gas transmission companies, which remain subject to the FERC's jurisdiction These initiatives may also affect certain transportation of gas by intrastate pipelines

Natural Gas Transmission's U S operations are subject to the jurisdiction of the EPA and state and local environmental agencies (For a discussion of environmental regulation, see "Environmental Matters" in this section) Natural Gas Transmission's interstate natural gas pipelines are also subject to the regulations of the DOT concerning pipeline safety

The natural gas transmission, storage and distribution operations in Canada are subject to regulation by the NEB and provincial agencies in Canada, such as the OEB. These agencies have jurisdiction similar to the FERC for regulating rates, regulating the operations of facilities and construction of any additional facilities. Natural Gas Transmission's federally regulated gathering and processing facilities and business in Western Canada is regulated by the NEB pursuant to a framework for light-handed regulation under which the NEB acts on a complaints basis for rates associated with that business. Similarly, the rates charged by the Midstream operation for gathering and processing services in Western Canada are regulated on a complaints basis by applicable provincial regulators. The Empress NGL businesses are not under any form of rate regulation.

FIELD SERVICES

As previously discussed, effective January 2, 2007, Duke Energy consummated the spin-off of the natural gas transmission businesses (Spectra Energy), including Duke Energy's investment in DEFS, to shareholders. The following business description of Field Services relates to 2006 and is not intended to describe the business subsequent to the spin-off on January 2, 2007.

Field Services includes Duke Energy's investment in DEFS, which gathers, compresses, processes, transports, trades and markets, and stores natural gas; and fractionates, transports, gathers, treats, processes, trades and markets, and stores NGLs. In July 2005, Duke Energy completed the disposition of its 19.7% interest in DEFS, which resulted in Duke Energy and ConocoPhillips becoming equal 50% owners in DEFS. The DEFS disposition transaction included the transfer to Duke Energy of DEFS' Canadian Midstream business. Additionally, the disposition transaction included the acquisition of ConocoPhillips' interest in the Empress System. Subsequent to the closing of the DEFS disposition transaction, effective on July 1, 2005, DEFS was no longer consolidated into Duke Energy's consolidated financial statements and is accounted for by Duke Energy as an equity method investment. The Canadian Midstream business and the Empress System have been transferred to the Natural Gas Transmission segment. Additionally, in February 2005, DEFS sold its wholly-owned subsidiary, Texas Eastern Products Pipeline Company, LLC (TEPPCO GP), the general partner of TEPPCO Partners L.P. (TEPPCO LP), and Duke Energy sold its limited partner interest in TEPPCO LP., in each case to Enterprise GP Holdings LP (EPCO), an unrelated third party.

In 2005, DEFS formed DCP Midstream Partners, LP (a master limited partnership). DCP Midstream Partners, LP (DCPLP) completed an IPO transaction in December 2005. As a result, DEFS has a 42 percent ownership interest in DCPLP, consisting of a 40 percent limited partner ownership interest and a 2 percent general partner ownership interest. DEFS owns 100 percent of the general partner of DCPLP.

DEFS operates in sixteen states in the United States (Alabama, Arkansas, Colorado, Kansas, Louisiana, Maine, Massachusetts, Mississippi, New Mexico, New York, Oklahoma, Pennsylvania, Texas, Rhode Island, Vermont and Wyoming). DEFS' gathering systems include connections to several interstate and intrastate natural gas and NGL pipeline systems and one natural gas storage facility. DEFS gathers raw natural gas through gathering systems located in seven major natural gas producing regions: Permian, Mid-Continent, East Texas-North Louisiana, South, Central, Rocky Mountain and Gulf Coast. DEFS owns or operates approximately 56,000 miles of gathering and transmission pipe, with approximately 34,000 active receipt points.

DEFS' natural gas processing operations separate raw natural gas that has been gathered on its own systems and third-party systems into condensate, NGLs and residue gas. DEFS processes the raw natural gas at 53 natural gas processing facilities.

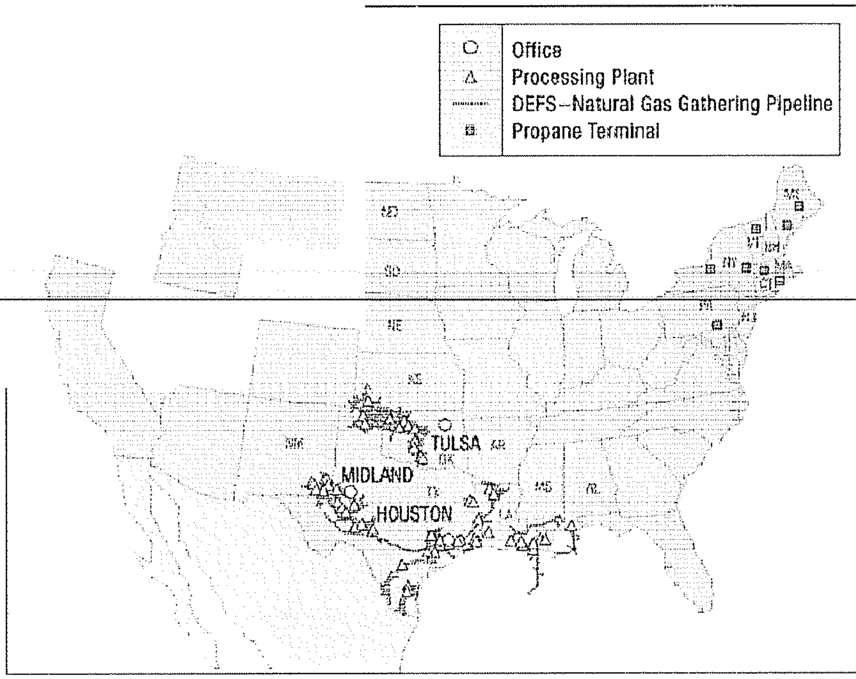
The NGLs separated from the raw natural gas are either sold and transported as NGL raw mix, or further separated through a fractionation process into their individual components (ethane, propane, butane and natural gasoline) and then sold as components. DEFS fractionates NGL raw mix at six processing facilities that it owns and operates and at four third-party-operated facilities in which it has an ownership interest. In addition, DEFS operates a propane wholesale marketing business. DEFS sells NGLs to a variety of customers ranging from large, multi-national petrochemical and refining companies to small, regional retail propane distributors. Substantially all of its NGL sales are at market-based prices.

The residue gas separated from the raw natural gas is sold at market-based prices to marketers and end-users, including large industrial customers and natural gas and electric utilities serving individual consumers. DEFS markets residue gas directly or through its wholly owned gas marketing company and its affiliates. DEFS also stores residue gas at its 8 billion-cubic-foot (Bcf) natural gas storage facility.

DEFS uses NGL trading and storage at the Mont Belvieu, Texas and Conway, Kansas NGL market centers to manage its price risk and to provide additional services to its customers. Asset-based gas trading and marketing activities are supported by ownership of the Spindletop storage facility and various intrastate pipelines which provide access to market centers/hubs such as Katy, Texas, and the Houston Ship Channel. DEFS undertakes these NGL and gas trading activities through the use of fixed forward sales, basis and spread trades, storage opportunities, put/call options, term contracts and spot market trading. DEFS believes there are additional opportunities to grow its services with its customer base.

PART I

The following map includes DEFS' natural gas gathering systems, intrastate pipelines, regional offices and supply areas



DEFS' operating results are significantly impacted by changes in average NGL, natural gas and crude oil prices, which increased approximately 10%, decreased approximately 15% and increased approximately 15%, respectively, in 2006 compared to 2005 DEFS closely monitors the risks associated with these price changes, using NGL and crude forward contracts to mitigate the effect of such fluctuations on operating results (See "Management's Discussion and Analysis of Financial Condition and Results of Operations, Quantitative and Qualitative Disclosures About Market Risk" for a discussion of DEFS' exposure to changes in commodity prices)

Competition

In gathering and processing natural gas and in marketing and transporting natural gas and NGLs, DEFS competes with major integrated oil companies, major interstate and intrastate pipelines, national and local natural gas gatherers, and brokers, marketers and distributors of natural gas supplies Competition for natural gas supplies is based primarily on the reputation, efficiency and reliability of operations, the availability of gathering and transportation to high-demand markets, the pricing arrangement offered by the gatherer/processor and the ability of the gatherer/processor to obtain a satisfactory price for the producer's residue gas and extracted NGLs Competition for sales to customers is based primarily upon reliability, services offered, and price of delivered natural gas and NGLs

Regulation

The intrastate natural gas and NGL pipelines owned by DEFS are subject to state regulation To the extent that the natural gas intrastate pipelines provide services under Section 311 of the Natural Gas Policy Act of 1978, they are also subject to FERC regulation The interstate natural gas pipeline owned and operated by DEFS is subject to FERC regulation, but its natural gas gathering and processing activities are not subject to FERC regulation

DEFS is subject to the jurisdiction of the EPA and state and local environmental agencies (For more information, see "Environmental Matters" in this section) DEFS' natural gas transmission pipelines and some gathering pipelines are also subject to the regulations of the DOT, and in some cases, state agencies, concerning pipeline safety

Table of Contents

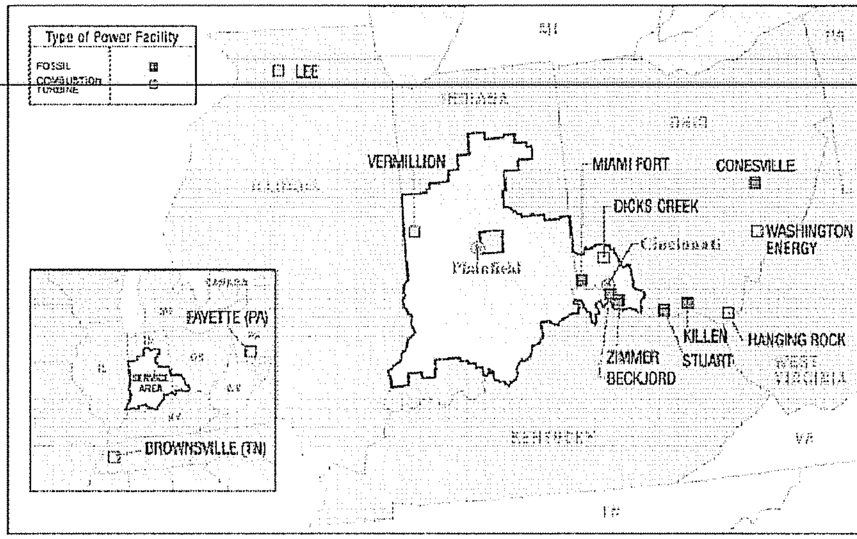
PART I

COMMERCIAL POWER

Commercial Power owns, operates and manages non-regulated merchant power plants and engages in the wholesale marketing and procurement of electric power, fuel and emission allowances related to these plants as well as other contractual positions Commercial Power also develops and implements customized energy solutions Commercial Power's generation asset fleet consists of Duke Energy Ohio's non-regulated generation in Ohio, acquired from Cinergy in April 2006 and the five Midwestern gas-fired merchant generation assets that were a portion of former DENA Commercial Power's assets are comprised of approximately 8,100 net megawatts of power generation primarily located in the Midwestern United States The asset portfolio has a diversified fuel mix with base-load and mid-merit coal-fired units as well as combined cycle and peaking natural gas-fired units Most of the generation asset output in Ohio has been contracted through the RSP described below See Item 2 "Properties" for further discussion of the generating facilities

Duke Energy – Midwest Power Generation

Non-Regulated Facilities



Commercial Power, through Duke Energy Generation Services (DEGS), is an on-site energy solutions and utility services provider Primarily through joint ventures, DEGS engages in utility systems construction, operation and maintenance of utility facilities, as well as cogeneration Cogeneration is the simultaneous production of two or more forms of usable energy from a single source DEGS also owns coal-based synthetic fuel production facilities which convert coal feedstock into synthetic fuel for sale to third parties The synthetic fuel produced in these facilities qualifies for tax credits through 2007 in accordance with Internal Revenue code Section 29/45K if certain requirements are satisfied

In October 2006, Duke Energy completed the sale of Commercial Power's energy marketing and trading activities, which were acquired in the Cinergy merger Additionally, in December 2006, Duke Energy completed the sale of Caledonia Power I, LLC, which is the project company that operated and managed the Caledonia peaking generation facility in Mississippi

Competition

Commercial Power primarily competes for wholesale contracts for the purchase and sale of electricity, coal, natural gas and emission allowances The market price of commodities and services, along with the quality and reliability of services provided, drive competition in the energy marketing business Commercial Power's main competitors include public utilities, wholesale power, coal and natural gas marketers and other merchant generation companies in the Midwestern United States, financial institutions and hedge funds engaged in energy commodity marketing and trading

Duke Energy Ohio operates under the RSP MBSSO which was approved by the PUCO in November 2004, and which provides price certainty through December 31, 2008 In March 2005, the OCC appealed the PUCO's approval of the MBSSO and in November 2006, the Ohio Supreme Court remanded the PUCO's order approving the MBSSO for further evidentiary support and explanation, and to require Duke Energy Ohio to disclose certain confidential commercial agreements between Duke Energy Ohio and other parties previously requested by the OCC Hearings on remand are expected to occur in March 2007 A major feature of the MBSSO is the POLR Charge Duke Energy Ohio has been collecting a POLR charge from non-residential customers since January 1, 2005, and from residential customers since January 1, 2006 The POLR charge consists of the following discrete charges:

- Annually Adjusted Component - intended to provide cost recovery primarily for environmental compliance expenditures This component is avoidable (or by-passable) for the first 25% of residential load and 50% of non-residential load to switch to an alternative electric service provider
- Infrastructure Maintenance Fund Charge - intended to compensate Duke Energy Ohio for committing its physical capacity This charge is unavoidable (or non-by-passable)
- System Reliability Tracker - intended to provide actual cost recovery for capacity purchases, purchased power, reserve capacity, and related market costs for purchases to meet capacity needs This charge is non-by-passable for residential load and by-passable for non-residential load under certain circumstances
- Rate Stabilization Charge - intended to compensate Duke Energy Ohio for maintaining a fixed price through 2008 This charge is by-passable by the first 25% of residential load and 50% of non-residential load to switch.
- Generation Prices and Fuel Recovery: A market price has been established for generation service A component of the market price is a fuel cost recovery mechanism that is adjusted quarterly for fuel, emission allowances, and certain purchased power costs, that exceed the amount originally included in the rates frozen in the Duke Energy Ohio transition plan These new prices were applied to non-residential customers beginning January 1, 2005 and to residential customers beginning January 1, 2006
- Transmission Cost Recovery: A transmission cost recovery mechanism was established beginning January 1, 2005 for non-residential customers and beginning January 1, 2006 for residential customers The transmission cost recovery mechanism is designed to permit Duke Energy Ohio to recover certain Midwest ISO charges, all FERC approved transmission costs, and all congestion costs allocable to retail ratepayers that are provided service by Duke Energy Ohio.

Regulation

Commercial Power is subject to regulation at the state level, primarily from PUCO and at the federal level, primarily from FERC The PUCO approves prices for all retail electric generation sales by Duke Energy Ohio for its native retail service territory

Regulations of FERC and the PUCO govern access to regulated electric customer and other data by non-regulated entities, and services provided between regulated and non-regulated energy affiliates These regulations affect the activities of Commercial Power

Other ongoing regulatory initiatives at both state and federal levels addressing market design, such as the development of capacity markets and real-time electricity markets, impact financial results from Commercial Power's marketing and generation activities

Commercial Power is subject to the jurisdiction of the EPA and state and local environmental agencies (For a discussion of environmental regulation, see "Environmental Matters" in this section)

INTERNATIONAL ENERGY

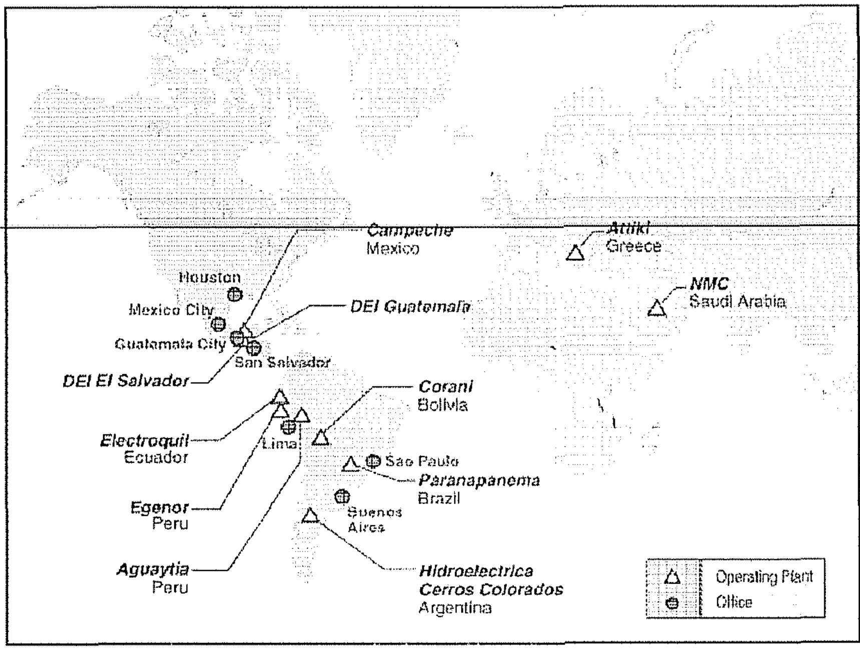
International Energy operates and manages power generation facilities and engages in sales and marketing of electric power and natural gas outside the U S and Canada It conducts operations primarily through DEI and its activities target power generation in Latin America Additionally, International Energy owns equity investments in: National Methanol Company (NMC), located in Saudi Arabia, which is a leading regional producer of methanol and methyl tertiary butyl ether (MTBE), Compania de Servicios de Compresion de Campeche, S A (Campeche), located in the Cantarell oil field in the Bay of Campeche, Mexico, which compresses and dehydrates natural gas and extracts NGL's, and Attiki Gas Supply S A (Attiki), located in Athens, Greece, which is a natural gas distributor and was acquired in connection with the Cinergy merger

Table of Contents

PART I

International Energy's customers include retail distributors, electric utilities, independent power producers, marketers and large industrial companies International Energy's current strategy is focused on optimizing the value of its current Latin American portfolio

International Energy owns, operates or has substantial interests in approximately 3,996 net MW of generation facilities The following map shows the locations of International Energy's facilities, including non-generation facilities in Saudi Arabia, Mexico and Greece



In December 2006, Duke Energy engaged in discussions with a potential buyer of International Energy's assets in Bolivia Such discussions to sell the assets were subject to a binding agreement between the parties, which was finalized in February 2007, and resulted in the sale of International Energy's 50 percent ownership interest in two hydroelectric power plants near Cochabamba, Bolivia to Econergy International

Competition and Regulation

International Energy's sales and marketing of electric power and natural gas competes directly with other generators and marketers serving its market areas Competitors are country and region-specific but include government owned electric generating companies, LDCs with self-generation capability and other privately owned electric generating companies The principal elements of competition are price and availability, terms of service, flexibility and reliability of service

A high percentage of International Energy's portfolio consists of base-load hydro electric generation facilities which compete with other forms of electric generation available to International Energy's customers and end-users, including natural gas and fuel oils Economic activity, conservation, legislation, governmental regulations, weather and other factors affect the supply and demand for electricity in the regions served by International Energy

International Energy's operations are subject to both country-specific and international laws and regulations (See "Environmental Matters" in this section)

CRESCENT

As previously discussed, effective September 7, 2006, Duke Energy completed the Crescent JV transaction, whereby Duke Energy sold an effective 50% interest in Crescent

[Table of Contents](#)

PART I

Crescent develops and manages high-quality commercial, residential and multi-family real estate projects, and manages land holdings, primarily in the Southeastern and Southwestern U S As of December 31, 2006, Crescent owned 1 1 million square feet of commercial, industrial and retail space, with an additional 0 3 million square feet under construction This portfolio included 0 5 million square feet of office space, 0 5 million square feet of warehouse space and 0 4 million square feet of retail space Crescent's residential developments include high-end country club and golf course communities, with individual lots sold to custom builders and tract developments sold to national builders Crescent had three multi-family communities at December 31, 2006, including two operating properties and one property under development As of December 31, 2006, Crescent also managed approximately 6,217 acres of land.

Competition and Regulation

Crescent competes with multiple regional and national real estate developers across its various business lines in the Southeastern and Southwestern U S Crescent's residential division sells developed lots to regional and national home builders and retail buyers, competing with other developers and home builders who have inventories of developed lots Crescent's commercial division leases office, industrial and retail space, competing with other public and private developers and owners of commercial property, including national real estate investment trusts (REITs). Similarly, Crescent's multi-family division leases apartment units primarily to individuals, competing with other private developers and multi-family REITs

Crescent is subject to the jurisdiction of the EPA and state and local environmental agencies (For a discussion of environmental regulation, see "Environmental Matters" in this section.)

OTHER

The remainder of Duke Energy's operations is presented as "Other " While it is not considered a business segment, Other primarily includes the operations discussed below

Other includes the remaining portion of Duke Energy's business formerly known as DENA, including its 100% owned affiliates Duke Energy Marketing America, LLC and Duke Energy Marketing Canada Corp Duke Energy also participates in DETM DETM is 40% owned by ExxonMobil Corporation and 60% owned by Duke Energy During the third quarter of 2005, Duke Energy's Board of Directors authorized and directed management to execute the sale or disposition of substantially all of former DENA's remaining assets and contracts outside the Midwestern United States and certain contractual positions related to the Midwestern assets Management retained former DENA's Midwestern generation assets (which are included in the Commercial Power segment), consisting of approximately 3,600 megawatts of power generation, and certain contracts related to the Midwestern generating facilities, as the merger with Cinergy provided a sustainable business model for those assets. The exit plan was completed in the second quarter of 2006

The results of operations of former DENA's Western and Eastern United States generation assets, including related commodity contracts, the divested Ft Frances generation assets, contracts related to former DENA's energy marketing and management activities and certain general and administrative costs, are required to be presented as discontinued operations classification for current and prior periods in the accompanying Consolidated Statements of Operations In addition, the results for DETM will continue to be reported in continuing operations until the wind down of these operations is complete

During 2006, Other also included certain unallocated corporate costs, certain discontinued hedges, DukeNet, Duke Energy's 50% interest in D/FD, Cinergy's equity financing business and Bison. Duke Energy had exited the merchant finance business at Duke Capital Partners LLC (DCP) as of the end of 2005 and all of the results of operations for DCP for the years ended December 31, 2005 and 2004 have been classified as discontinued operations

DukeNet develops, owns and operates a fiber optic communications network, primarily in the Carolinas, serving wireless, local and long-distance communications companies, internet service providers and other businesses and organizations

During 2003, Duke Energy determined that it would exit the refined products business at Duke Energy Merchants, LLC (DEM) in an orderly manner As of December 31, 2006, DEM has completed the exit of its business DEM previously engaged in commodity buying and selling, and risk management and financial services in non-regulated energy commodity markets other than physical natural gas and power (such as petroleum products) The results of operations for DEM have been classified as discontinued operations for all periods presented

D/FD is a 50/50 partnership between subsidiaries of Duke Energy and Fluor During 2003, Duke Energy and Fluor announced that they would dissolve D/FD, and adopted a plan for an orderly wind-down of D/FD's business The wind-down has been substantially completed as of December 31, 2006 Previously, D/FD provided comprehensive engineering, procurement, construction, commissioning and operating plant services for fossil-fueled electric power generating facilities worldwide

PART I

Cinergy has a business which invests in start up businesses utilizing new energy technologies as well as technologies utilizing energy infrastructure, such as broadband over power line services

Bison's principal activities, as a captive insurance entity, include the insurance and reinsurance of various business risks and losses, such as workers compensation, property, business interruption, and general liability of subsidiaries and affiliates of Duke Energy Bison also participates in reinsurance activities with certain third parties, on a limited basis

Competition and Regulation

The entities within Other are subject to the jurisdiction of the EPA and state and local environmental agencies (For a discussion of environmental regulation, see "Environmental Matters" in this section)

ENVIRONMENTAL MATTERS

Duke Energy is subject to international, federal, state and local laws and regulations with regard to air and water quality, hazardous and solid waste disposal and other environmental matters Environmental laws and regulations affecting Duke Energy include, but are not limited to:

- The Clean Air Act, as well as state laws and regulations impacting air emissions, including State Implementation Plans related to existing and new national ambient air quality standards for ozone and particulate matter. Owners and/or operators of air emission sources are responsible for obtaining permits and for annual compliance and reporting.
- The Clean Water Act which requires permits for facilities that discharge wastewaters into the environment
- The Comprehensive Environmental Response, Compensation and Liability Act, which can require any individual or entity that currently owns or in the past may have owned or operated a disposal site, as well as transporters or generators of hazardous substances sent to a disposal site, to share in remediation costs
- The Solid Waste Disposal Act, as amended by the Resource Conservation and Recovery Act, which requires certain solid wastes, including hazardous wastes, to be managed pursuant to a comprehensive regulatory regime
- The National Environmental Policy Act, which requires federal agencies to consider potential environmental impacts in their decisions, including siting approvals
- The North Carolina clean air legislation that freezes electric utility rates from June 20, 2002 to December 31, 2007 (rate freeze period), subject to certain conditions, in order for North Carolina electric utilities, including Duke Energy, to significantly reduce emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_X) from coal-fired power plants in the state The legislation allows electric utilities, including Duke Energy, to accelerate the recovery of compliance costs by amortizing them over seven years (2003-2009)

(For more information on environmental matters involving Duke Energy, including possible liability and capital costs, see Notes 4 and 17 to the Consolidated Financial Statements, "Regulatory Matters," and "Commitments and Contingencies—Environmental," respectively)

Except to the extent discussed in Note 4 to the Consolidated Financial Statements, "Regulatory Matters," and Note 17 to the Consolidated Financial Statements, "Commitments and Contingencies," compliance with international, federal, state and local provisions regulating the discharge of materials into the environment, or otherwise protecting the environment, is incorporated into the routine cost structure of our various business units and is not expected to have a material adverse effect on the competitive position, consolidated results of operations, cash flows or financial position of Duke Energy

GEOGRAPHIC REGIONS

For a discussion of Duke Energy's foreign operations and the risks associated with them, see "Management's Discussion and Analysis of Results of Operations and Financial Condition, Quantitative and Qualitative Disclosures About Market Risk—Foreign Currency Risk," and Notes 3 and 8 to the Consolidated Financial Statements, "Business Segments" and "Risk Management and Hedging Activities, Credit Risk, and Financial Instruments," respectively

EMPLOYEES

On December 31, 2006, Duke Energy had approximately 25,600 employees A total of approximately 6,600 operating and maintenance employees were represented by unions

[Table of Contents](#)

PART I

EXECUTIVE OFFICERS OF DUKE ENERGY

HENRY B BARRON JR , 56, Group Executive and Chief Nuclear Officer Mr Barron assumed his current position in November 2006 Prior to that, he served as Group Vice President, Nuclear Generation and Chief Nuclear Officer since April 2006, upon the merger of Duke Energy and Cinergy Until the merger of Duke Energy and Cinergy, Mr Barron served as Group Vice President, Nuclear Generation and Chief Nuclear Officer of Duke Energy since March 2004 Prior to that, he served as Executive Vice President, Nuclear Generation of Duke Energy from January 2004 to March 2004, Senior Vice President, Nuclear Operations of Duke Energy from September 2002 to January 2004 and Vice President, McGuire Nuclear Station of Duke Energy from March 1999 to September 2002

LYNN J GOOD, 47, Senior Vice President and Treasurer Ms Good assumed her current position in December 2006 Prior to that, she served as Vice President and Treasurer since April 2006, upon the merger of Duke Energy and Cinergy Until the merger of Duke Energy and Cinergy, Ms Good served as Executive Vice President and Chief Financial Officer of Cinergy from August 2005, Vice President, Finance and Controller of Cinergy from November 2003 to August 2005 and Vice President, Financial Project Strategy of Cinergy from May 2003 to November 2003 Prior to that, Ms Good was a partner with the international accounting firm Deloitte & Touche LLP in Cincinnati, Ohio from May 2002 to May 2003 And, prior to that, she was a partner with the international accounting firm Arthur Anderson LLP from 1992 to May 2002

DAVID L HAUSER, 55, Group Executive and Chief Financial Officer Mr Hauser assumed his current position in April 2006, upon the merger of Duke Energy and Cinergy Until the merger of Duke Energy and Cinergy, Mr Hauser served as Group Vice President and Chief Financial Officer of Duke Energy since March 2004 and as Acting Chief Financial Officer of Duke Energy from December 2003 to March 2004 Prior to that, he served as Senior Vice President and Treasurer of Duke Energy from July 1998 to December 2003

MARC E MANLY, 54, Group Executive and Chief Legal Officer Mr Manly assumed his current position in April 2006, upon the merger of Duke Energy and Cinergy Until the merger of Duke Energy and Cinergy, Mr Manly served as Executive Vice President and Chief Legal Officer of Cinergy since November 2002 Prior to that, Mr Manly served as Managing Director, Law and Governmental Affairs, General Counsel and Corporate Secretary of NewPower Holdings, Inc from April 2000 to August 2002 On June 11, 2002, New Power Holdings, Inc and its affiliates, TNPC Holdings, Inc and the NewPower Company, filed a petition for relief under Chapter 11 of The United States Bankruptcy Code

WILLIAM R McCOLLUM JR, 55, Group Executive and Chief Regulated Generation Officer Mr McCollum assumed his current position in November 2006 Prior to that, he served as Group Vice President, Regulated Fossil/Hydro Generation since April 2006, upon the merger of Duke Energy and Cinergy Until the merger of Duke Energy and Cinergy, Mr McCollum served as Vice President, Strategy and Business Development for Duke Energy Carolinas since January 2005 Prior to that, Mr McCollum served as Senior Vice President, Nuclear Support of Duke Energy from September 2002 to January 2005 and Vice Presdient, Oconee Nuclear Station of Duke Energy from March 1999 to September 2002

THOMAS C O'CONNOR, 51, Group Executive and President, Commercial Businesses Mr O'Connor assumed his current position in October 2006 Prior to that he served as Group Executive and Chief Operating Officer, U S Franchised Electric and Gas since April 2006, upon the merger of Duke Energy and Cinergy Until the merger of Duke Energy and Cinergy, Mr O'Connor served as President and Chief Executive Officer of Duke Energy Gas Transmission since December 2002 He has also served in leadership positions with Duke Energy's pipeline operations since 1994

JAMES E ROGERS, 59, Chairman, President and Chief Executive Officer Mr Rogers assumed the role of Chief Executive Officer and President in April 2006, upon the merger of Duke Energy and Cinergy and assumed the role of Chairman on January 2, 2007 Until the merger of Duke Energy and Cinergy, Mr Rogers served as Chairman of the Board of Cinergy since 2000 and as Chief Executive Officer of Cinergy since 1995

CHRISTOPHER C ROLFE, 56, Group Executive and Chief Administrative Officer Mr Rolfe assumed his current position in November 2006 Prior to that, he served as Group Executive and Chief Human Resources Officer since April 2006, upon the merger of Duke Energy and Cinergy Until the merger of Duke Energy and Cinergy, Mr Rolfe served as Vice President, Human Resources of Duke Energy since January 2005 Prior to that, Mr Rolfe served as Senior Vice President, Strategy, Planning & Human Resources of Duke Energy from March 2003 to January 2005 and Senior Vice President, Human Resources of Duke Energy from January 2001 to March 2003

RUTH G SHAW, 58, Executive Advisor to the Chairman, President and Chief Executive Officer Dr Shaw assumed her current position in October 2006 Prior to that she served as Group Executive, Public Policy and President, Duke Nuclear since April 2006, upon the merger of Duke Energy and Cinergy Until the merger of Duke Energy and Cinergy, Dr Shaw served as President and Chief Executive Officer, Duke Energy Carolinas since February 2003 Prior to that Dr Shaw served as Executive Vice President and Chief Administrative Officer of Duke Energy Carolinas from 1997 to February 2003

PART I

B KEITH TRENT, 47, Group Executive and Chief Strategy and Policy Officer Mr Trent assumed his current position in October 2006 Prior to that he served as Group Executive and Chief Development Officer since April 2006, upon the merger of Duke Energy and Cinergy Until the merger of Duke Energy and Cinergy, Mr Trent served as Executive Vice President, General Counsel and Secretary of Duke Energy since March 2005 Prior to that he served as General Counsel, Litigation of Duke Energy from May 2002 to March 2005 Prior to that Mr Trent served as a partner in the law firm Snell, Brannian & Trent since October 1991

JAMES L TURNER, 47, Group Executive and President, U S Franchised Electric and Gas Mr Turner assumed his current position in October 2006 Prior to that he served as Group Executive and Chief Commercial Officer, U S Franchised Electric and Gas since April 2006, upon the merger of Duke Energy and Cinergy Until the merger of Duke Energy and Cinergy, Mr Turner served as President of Cinergy since 2005, Executive Vice President and Chief Financial Officer of Cinergy from 2004 to 2005 and Executive Vice President and Chief Executive Officer, Regulated Business Unit of Cinergy from 2001 to 2004

STEVEN K YOUNG, 48, Senior Vice President and Controller Mr Young assumed his current position in December 2006 Prior to that he served as Vice President and Controller since April 2006, upon the merger of Duke Energy and Cinergy Until the merger of Duke Energy and Cinergy, Mr Young served as Vice President and Controller of Duke Energy since June 2005 Prior to that Mr Young served as Senior Vice President and Chief Financial Officer of Duke Energy Carolinas from March 2003 to June 2005 and as Vice President, Rates and Regulatory Affairs of Duke Energy Carolinas from March 1998 to March 2003

Executive officers are elected annually by the Board of Directors They serve until the first meeting of the Board of Directors following the annual meeting of shareholders and until their successors are duly elected

There are no family relationships between any of the executive officers, nor any arrangement or understanding between any executive officer and any other person involved in officer selection

Item 1A. Risk Factors.

The risk factors discussed herein relate specifically to risks associated with Duke Energy subsequent to the spin-off of its natural gas businesses in January 2007 Accordingly, risks associated with the Spectra Energy businesses are not discussed in this section

Duke Energy may be unable to achieve some or all of the benefits that are expected to be achieved in connection with the spin-off of its natural gas businesses in January 2007.

Duke Energy may not be able to achieve the full strategic and financial benefits that are expected to result from the spin-off transaction or such benefits may be delayed or may not occur at all

Duke Energy's franchised electric revenues, earnings and results are dependent on state legislation and regulation that affect electric generation, transmission, distribution and related activities, which may limit Duke Energy's ability to recover costs.

Duke Energy's franchised electric businesses are regulated on a cost-of-service/rate-of-return basis subject to the statutes and regulatory commission rules and procedures of North Carolina, South Carolina, Ohio, Indiana and Kentucky If Duke Energy's franchised electric earnings exceed the returns established by the state regulatory commissions, Duke Energy's retail electric rates may be subject to review by the commissions and possible reduction, which may decrease Duke Energy's future earnings Additionally, if regulatory bodies do not allow recovery of costs incurred in providing service on a timely basis, Duke Energy's future earnings could be negatively impacted

Duke Energy may incur substantial costs and liabilities due to Duke Energy's ownership and operation of nuclear generating facilities.

Duke Energy's ownership interest in and operation of three nuclear stations subject Duke Energy to various risks including, among other things: the potential harmful effects on the environment and human health resulting from the operation of nuclear facilities and the storage, handling and disposal of radioactive materials; limitations on the amounts and types of insurance commercially available to cover losses that might arise in connection with nuclear operations; and uncertainties with respect to the technological and financial aspects of decommissioning nuclear plants at the end of their licensed lives

Duke Energy's ownership and operation of nuclear generation facilities requires Duke Energy to meet licensing and safety-related requirements imposed by the NRC In the event of non-compliance, the NRC may increase regulatory oversight, impose fines, and/or shut down a unit, depending upon its assessment of the severity of the situation. Revised security and safety requirements promulgated by the

NRC, which could be prompted by, among other things, events within or outside of Duke Energy's control, such as a serious nuclear incident at a facility owned by a third-party, could necessitate substantial capital and other expenditures at Duke Energy's nuclear plants, as well as assessments against Duke Energy to cover third-party losses In addition, if a serious nuclear incident were to occur, it could have a material adverse effect on Duke Energy's results of operations and financial condition

Duke Energy's ownership and operation of nuclear generation facilities also requires Duke Energy to maintain funded trusts that are intended to pay for the decommissioning costs of Duke Energy's nuclear power plants Poor investment performance of these decommissioning trusts' holdings and other factors impacting decommissioning costs could unfavorably impact Duke Energy's liquidity and results of operations as Duke Energy could be required to significantly increase its cash contributions to the decommissioning trusts

Duke Energy's plans for future expansion and modernization of its generation fleet subject it to risk of future price and inflationary increases in the cost of such expenditures as well as the risk of recovering such costs in a timely manner which could materially impact Duke Energy's financial condition, results of operations or cash flows.

During the three-year period from 2007 to 2009, Duke Energy anticipates annual capital expenditures of approximately $3 5 billion, for a total of approximately $10 billion Duke Energy has begun to see significant increases in the estimated costs of these capital projects as a result of strong domestic and international demand for the material, equipment, and labor necessary to construct these facilities Increases in costs related to materials and services required to expand and modernize Duke Energy's generation fleet as well as Duke Energy's ability to recover these costs in a timely manner could materially impact Duke Energy's consolidated financial condition, results of operations or cash flows

Duke Energy's sales may decrease if Duke Energy is unable to gain adequate, reliable and affordable access to transmission assets

Duke Energy depends on transmission and distribution facilities owned and operated by utilities and other energy companies to deliver the electricity Duke Energy sells to the wholesale market FERC's power transmission regulations require wholesale electric transmission services to be offered on an open-access, non-discriminatory basis; however, not all markets are as open and accessible as needed If transmission is disrupted, or if transmission capacity is inadequate, Duke Energy's ability to sell and deliver products may be hindered Such disruptions could also hinder Duke Energy from providing electricity to Duke Energy's retail electric customers and may materially adversely affect Duke Energy's business

The different regional power markets have changing regulatory structures, which could affect Duke Energy's growth and performance in these regions In addition, the independent system operators who oversee the transmission systems in regional power markets have imposed in the past, and may impose in the future, price limitations and other mechanisms to address volatility in the power markets These types of price limitations and other mechanisms may adversely impact the profitability of Duke Energy's wholesale power marketing and trading business

Duke Energy may be unable to secure long term power purchase agreements or transmission agreements, which could expose Duke Energy's sales to increased volatility.

In the future, Duke Energy may not be able to secure long-term power purchase agreements for Duke Energy's unregulated power generation facilities If Duke Energy is unable to secure these types of agreements, Duke Energy's sales volumes would be exposed to increased volatility Without the benefit of long-term power purchase agreements, Duke Energy cannot assure that it will be able to sell the power generated by Duke Energy's facilities or that Duke Energy's facilities will be able to operate profitably The inability to secure these agreements could materially adversely affect Duke Energy's results and business

Competition in the unregulated markets in which Duke Energy operates may adversely affect the growth and profitability of Duke Energy's business

Duke Energy may not be able to respond in a timely or effective manner to the many changes designed to increase competition in the electricity industry To the extent competitive pressures increase, the economics of Duke Energy's business may come under long-term pressure

In addition, regulatory changes have been proposed to increase access to electricity transmission grids by utility and non-utility purchasers and sellers of electricity These changes could continue the disaggregation of many vertically-integrated utilities into separate generation, transmission, distribution and retail businesses As a result, a significant number of additional competitors could become active in the wholesale power generation segment of Duke Energy's industry

Duke Energy may also face competition from new competitors that have greater financial resources than Duke Energy does, seeking attractive opportunities to acquire or develop energy assets or energy trading operations both in the United States and abroad These new competitors may include sophisticated financial institutions, some of which are already entering the energy trading and marketing sector, and international energy players, which may enter regulated or unregulated energy businesses This competition may adversely affect Duke Energy's ability to make investments or acquisitions.

Duke Energy must meet credit quality standards. If Duke Energy or its rated subsidiaries are unable to maintain an investment grade credit rating, Duke Energy would be required under credit agreements to provide collateral in the form of letters of credit or cash, which may materially adversely affect Duke Energy's liquidity. Duke Energy cannot be sure that it and its rated subsidiaries will maintain investment grade credit ratings

Each of Duke Energy's and its rated subsidiaries senior unsecured long-term debt is rated investment grade by various rating agencies Duke Energy cannot be sure that the senior unsecured long-term debt of Duke Energy or its rated subsidiaries will be rated investment grade

If the rating agencies were to rate Duke Energy or its rated subsidiaries below investment grade, the entity's borrowing costs would increase, perhaps significantly In addition, the entity would likely be required to pay a higher interest rate in future financings, and its potential pool of investors and funding sources would likely decrease Further, if its short-term debt rating were to fall, the entity's access to the commercial paper market could be significantly limited. Any downgrade or other event negatively affecting the credit ratings of Duke Energy's subsidiaries could make their costs of borrowing higher or access to funding sources more limited, which in turn could increase Duke Energy's need to provide liquidity in the form of capital contributions or loans to such subsidiaries, thus reducing the liquidity and borrowing availability of the consolidated group.

A downgrade below investment grade could also trigger termination clauses in some interest rate and foreign exchange derivative agreements, which would require cash payments All of these events would likely reduce Duke Energy's liquidity and profitability and could have a material adverse effect on Duke Energy's financial position, results of operations or cash flows.

Duke Energy relies on access to short-term money markets and longer-term capital markets to finance Duke Energy's capital requirements and support Duke Energy's liquidity needs, and Duke Energy's access to those markets can be adversely affected by a number of conditions, many of which are beyond Duke Energy's control.

Duke Energy's business is financed to a large degree through debt and the maturity and repayment profile of debt used to finance investments often does not correlate to cash flows from Duke Energy's assets Accordingly, Duke Energy relies on access to both short-term money markets and longer-term capital markets as a source of liquidity for capital requirements not satisfied by the cash flow from Duke Energy's operations and to fund investments originally financed through debt instruments with disparate maturities. If Duke Energy is not able to access capital at competitive rates, Duke Energy's ability to finance Duke Energy's operations and implement Duke Energy's strategy will be adversely affected

Market disruptions may increase Duke Energy's cost of borrowing or adversely affect Duke Energy's ability to access one or more financial markets. Such disruptions could include: economic downturns; the bankruptcy of an unrelated energy company; capital market conditions generally; market prices for electricity and gas; terrorist attacks or threatened attacks on Duke Energy's facilities or unrelated energy companies; or the overall health of the energy industry Restrictions on Duke Energy's ability to access financial markets may also affect Duke Energy's ability to execute Duke Energy's business plan as scheduled An inability to access capital may limit Duke Energy's ability to pursue improvements or acquisitions that Duke Energy may otherwise rely on for future growth

Duke Energy maintains revolving credit facilities to provide back-up for commercial paper programs and/or letters of credit at various entities These facilities typically include financial covenants which limit the amount of debt that can be outstanding as a percentage of the total capital for the specific entity Failure to maintain these covenants at a particular entity could preclude that entity from issuing commercial paper or letters of credit or borrowing under the revolving credit facility and could require other of Duke Energy's affiliates to immediately pay down any outstanding drawn amounts under other revolving credit agreements

Duke Energy's investments and projects located outside of the United States expose Duke Energy to risks related to laws of other countries, taxes, economic conditions, political conditions and policies of foreign governments These risks may delay or reduce Duke Energy's realization of value from Duke Energy's international projects.

Duke Energy currently owns and may acquire and/or dispose of material energy-related investments and projects outside the United States. The economic, regulatory, market and political conditions in some of the countries where Duke Energy has interests or in which

Duke Energy may explore development, acquisition or investment opportunities could present risks related to, among others, Duke Energy's ability to obtain financing on suitable terms, Duke Energy's customers' ability to honor their obligations with respect to projects and investments, delays in construction, limitations on Duke Energy's ability to enforce legal rights, and interruption of business, as well as risks of war, expropriation, nationalization, renegotiation, trade sanctions or nullification of existing contracts and changes in law, regulations, market rules or tax policy

Duke Energy's investments and projects located outside of the United States expose Duke Energy to risks related to fluctuations in currency rates. These risks, and Duke Energy's activities to mitigate such risks, may adversely affect Duke Energy's cash flows and results of operations.

Duke Energy's operations and investments outside the United States expose Duke Energy to risks related to fluctuations in currency rates As each local currency's value changes relative to the U S dollar—Duke Energy's principal reporting currency—the value in U S dollars of Duke Energy's assets and liabilities in such locality and the cash flows generated in such locality, expressed in U S dollars, also change

Duke Energy selectively mitigates some risks associated with foreign currency fluctuations by, among other things, indexing contracts to the U S dollar and/or local inflation rates, hedging through debt denominated or issued in the foreign currency and hedging through foreign currency derivatives These efforts, however, may not be effective and, in some cases, may expose Duke Energy to other risks that could negatively affect Duke Energy's cash flows and results of operations

Duke Energy's primary foreign currency rate exposure is expected to be to the Brazilian Real. A 10% devaluation in the currency exchange rate in all of Duke Energy's exposure currencies would result in an estimated net loss on the translation of local currency earnings of approximately $7 million The consolidated balance sheets would be negatively impacted by such a devaluation by approximately $120 million through cumulative currency translation adjustments

Duke Energy is exposed to credit risk of counterparties with whom Duke Energy does business.

Adverse economic conditions affecting, or financial difficulties of, counterparties with whom Duke Energy does business could impair the ability of these counterparties to pay for Duke Energy's services or fulfill their contractual obligations, or cause them to delay such payments or obligations Duke Energy depends on these counterparties to remit payments on a timely basis Any delay or default in payment could adversely affect Duke Energy's cash flows, financial position or results of operations

Poor investment performance of pension plan holdings and other factors impacting pension plan costs could unfavorably impact Duke Energy's liquidity and results of operations.

Duke Energy's costs of providing non-contributory defined benefit pension plans are dependent upon a number of factors, such as the rates of return on plan assets, discount rates, the level of interest rates used to measure the required minimum funding levels of the plans, future government regulation and Duke Energy's required or voluntary contributions made to the plans While Duke Energy complies with the minimum funding requirements as of September 30, 2006, Duke Energy has certain qualified U S pension plans with obligations which exceeded the value of plan assets by approximately $500 million Without sustained growth in the pension investments over time to increase the value of Duke Energy's plan assets and depending upon the other factors impacting Duke Energy's costs as listed above, Duke Energy could be required to fund its plans with significant amounts of cash Such cash funding obligations could have a material impact on Duke Energy's cash flows, financial position or results of operations

Duke Energy is subject to numerous environmental laws and regulations that require significant capital expenditures, can increase Duke Energy's cost of operations, and which may impact or limit Duke Energy's business plans, or expose Duke Energy to environmental liabilities.

Duke Energy is subject to numerous environmental laws and regulations affecting many aspects of Duke Energy's present and future operations, including air emissions (such as reducing NO_x, SO_2 and mercury emissions in the U S , or potential future control of greenhouse-gas emissions), water quality, wastewater discharges, solid waste and hazardous waste These laws and regulations can result in increased capital, operating, and other costs. These laws and regulations generally require Duke Energy to obtain and comply with a wide variety of environmental licenses, permits, inspections and other approvals Compliance with environmental laws and regulations can require significant expenditures, including expenditures for clean up costs and damages arising out of contaminated properties, and failure to comply with environmental regulations may result in the imposition of fines, penalties and injunctive measures affecting operating assets The steps Duke Energy takes to ensure that its facilities are in compliance could be prohibitively expensive As a result, Duke Energy may be required to shut down or alter the operation of its facilities, which may cause Duke Energy to incur losses Further, Duke Energy's regulatory rate structure and Duke Energy's contracts with customers may not necessarily allow Duke Energy to recover capital costs Duke Energy incurs to comply with new environmental regulations Also, Duke Energy may not be able to obtain or maintain from time to time all required environmental regulatory approvals for Duke Energy's operating assets or development projects If there is a delay in obtaining any required environmental regulatory approvals, if Duke Energy fails to obtain and comply with them or if environmental laws or regulations change and become more stringent, then the operation of Duke Energy's facilities or the development of new facilities could be prevented, delayed or become subject to additional costs Although it is not expected that the costs of complying with current environmental regulations will have a material adverse effect on Duke Energy's cash flows, financial position or results of operations, no assurance can be made that the costs of complying with environmental regulations in the future will not have such an effect

There is growing consensus that some form of regulation will be forthcoming at the federal level with respect to greenhouse gas emissions (including CO_2) and such regulation could result in the creation of substantial additional costs in the form of taxes or emission allowances

In addition, Duke Energy is generally responsible for on-site liabilities, and in some cases off-site liabilities, associated with the environmental condition of Duke Energy's power generation facilities and natural gas assets which Duke Energy has acquired or developed, regardless of when the liabilities arose and whether they are known or unknown In connection with some acquisitions and sales of assets, Duke Energy may obtain, or be required to provide, indemnification against some environmental liabilities If Duke Energy incurs a material liability, or the other party to a transaction fails to meet its indemnification obligations to Duke Energy, Duke Energy could suffer material losses

Deregulation or restructuring in the electric industry may result in increased competition and unrecovered costs that could adversely affect Duke Energy's financial condition, results of operations or cash flows and Duke Energy's utilities' businesses.

Increased competition resulting from deregulation or restructuring efforts, including from the Energy Policy Act of 2005, could have a significant adverse financial impact on Duke Energy and Duke Energy's utility subsidiaries and consequently on Duke Energy's results of operations, financial position, or cash flows Increased competition could also result in increased pressure to lower costs, including the cost of electricity Retail competition and the unbundling of regulated energy and gas service could have a significant adverse financial impact on Duke Energy and Duke Energy's subsidiaries due to an impairment of assets, a loss of retail customers, lower profit margins or increased costs of capital Duke Energy cannot predict the extent and timing of entry by additional competitors into the electric markets Duke Energy cannot predict when Duke Energy will be subject to changes in legislation or regulation, nor can Duke Energy predict the impact of these changes on its financial position, results of operations or cash flows

Duke Energy is involved in numerous legal proceedings, the outcome of which are uncertain, and resolution adverse to Duke Energy could negatively affect Duke Energy's cash flows, financial condition or results of operations.

Duke Energy is subject to numerous legal proceedings Litigation is subject to many uncertainties and Duke Energy cannot predict the outcome of individual matters with assurance It is reasonably possible that the final resolution of some of the matters in which Duke Energy is involved could require Duke Energy to make additional expenditures, in excess of established reserves, over an extended period of time and in a range of amounts that could have a material effect on Duke Energy's cash flows and results of operations Similarly, it is reasonably possible that the terms of resolution could require Duke Energy to change Duke Energy's business practices and procedures, which could also have a material effect on Duke Energy's cash flows, financial position or results of operations

Duke Energy's results of operations may be negatively affected by sustained downturns or sluggishness in the economy, including low levels in the market prices of commodities, all of which are beyond Duke Energy's control.

Sustained downturns or sluggishness in the economy generally affect the markets in which Duke Energy operates and negatively influence Duke Energy's energy operations Declines in demand for electricity as a result of economic downturns in Duke Energy's franchised electric service territories will reduce overall electricity sales and lessen Duke Energy's cash flows, especially as Duke Energy's industrial customers reduce production and, therefore, consumption of electricity and gas Although Duke Energy's franchised electric business is subject to regulated allowable rates of return and recovery of fuel costs under a fuel adjustment clause, overall declines in electricity sold as a result of economic downturn or recession could reduce revenues and cash flows, thus diminishing results of operations

Duke Energy also sells electricity into the spot market or other competitive power markets on a contractual basis With respect to such transactions, Duke Energy is not guaranteed any rate of return on Duke Energy's capital investments through mandated rates, and Duke Energy's revenues and results of operations are likely to depend, in large part, upon prevailing market prices in Duke Energy's regional markets and other competitive markets These market prices may fluctuate substantially over relatively short periods of time and could reduce Duke Energy's revenues and margins and thereby diminish Duke Energy's results of operations

Lower demand for the electricity Duke Energy sells and lower prices for electricity result from multiple factors that affect the markets where Duke Energy sells electricity including

- weather conditions, including abnormally mild winter or summer weather that cause lower energy usage for heating or cooling purposes, respectively, and periods of low rainfall that decrease Duke Energy's ability to generate hydroelectric energy;
- supply of and demand for energy commodities;
- illiquid markets including reductions in trading volumes which result in lower revenues and earnings;
- general economic conditions, including downturns in the U S or other economies which impact energy consumption particularly in which sales to industrial or large commercial customers comprise a significant portion of total sales;
- transmission or transportation constraints or inefficiencies which impact Duke Energy's merchant energy operations;
- availability of competitively priced alternative energy sources, which are preferred by some customers over electricity produced from coal, nuclear or gas plants, and of energy-efficient equipment which reduces energy demand;
- natural gas, crude oil and refined products production levels and prices;
- ability to procure satisfactory levels of inventory, such as coal;
- electric generation capacity surpluses which cause Duke Energy's merchant energy plants to generate and sell less electricity at lower prices and may cause some plants to become non-economical to operate.
- capacity and transmission service into, or out of, Duke Energy's markets;
- natural disasters, acts of terrorism, wars, embargoes and other catastrophic events to the extent they affect Duke Energy's operations and markets, as well as the cost and availability of insurance covering such risks; and
- federal, state and foreign energy and environmental regulation and legislation

These factors have led to industry-wide downturns that have resulted in the slowing down or stopping of construction of new power plants and announcements by Duke Energy and other energy suppliers and gas pipeline companies of plans to sell non-strategic assets, subject to regulatory constraints, in order to boost liquidity or strengthen balance sheets Proposed sales by other energy suppliers could increase the supply of the types of assets that Duke Energy is attempting to sell In addition, recent FERC actions addressing power market concerns could negatively impact the marketability of Duke Energy's electric generation assets

Duke Energy's operating results may fluctuate on a seasonal and quarterly basis.

Electric power generation is generally a seasonal business In most parts of the United States and other markets in which Duke Energy operates, demand for power peaks during the hot summer months, with market prices also peaking at that time In other areas, demand for power peaks during the winter Further, extreme weather conditions such as heat waves or winter storms could cause these seasonal fluctuations to be more pronounced As a result, in the future, the overall operating results of Duke Energy's businesses may fluctuate substantially on a seasonal and quarterly basis and thus make period comparison less relevant

Duke Energy's business is subject to extensive regulation that will affect Duke Energy's operations and costs.

Duke Energy is subject to regulation by FERC and the NRC, by federal, state and local authorities under environmental laws and by state public utility commissions under laws regulating Duke Energy's businesses Regulation affects almost every aspect of Duke Energy's businesses, including, among other things, Duke Energy's ability to: take fundamental business management actions; determine the terms and rates of Duke Energy's transmission and distribution businesses' services; make acquisitions; issue equity or debt securities; engage in transactions between Duke Energy's utilities and other subsidiaries and affiliates; and pay dividends Changes to these regulations are ongoing, and Duke Energy cannot predict the future course of changes in this regulatory environment or the ultimate effect that this changing regulatory environment will have on Duke Energy's business However, changes in regulation (including re-regulating previously deregulated markets) can cause delays in or affect business planning and transactions and can substantially increase Duke Energy's costs.

FERC has established certain market screens it employs to assess generation market power Certain of these screens are difficult for a franchised utility to pass In an order issued on June 30, 2005 the FERC revoked the authority for Duke Energy Carolinas to make wholesale power sales within its control area at market-based rates based on the FERC's determination that Duke Energy Carolinas failed one of the applicable market screens Under the FERC's order, Duke Energy Carolinas must pay partial refunds and may prospectively make wholesale power sales within its control area only at cost-based rates

PART I

Certain events in the energy markets beyond Duke Energy's control have increased the level of public and regulatory scrutiny in the energy industry and in the capital markets and could result in new laws or regulations which could have a negative impact on Duke Energy's results of operations.

Due to certain events in the energy markets, regulated energy companies have been under increased scrutiny by regulatory bodies, capital markets and credit rating agencies This increased scrutiny could lead to substantial changes in laws and regulations affecting Duke Energy, including new accounting standards that could change the way Duke Energy is required to record revenues, expenses, assets and liabilities These types of regulations could have a negative impact on Duke Energy's financial position, cash flows or results of operations or access to capital

Potential terrorist activities or military or other actions could adversely affect Duke Energy's business.

The continued threat of terrorism and the impact of retaliatory military and other action by the United States and its allies may lead to increased political, economic and financial market instability and volatility in prices for natural gas and oil which may materially adversely affect Duke Energy in ways Duke Energy cannot predict at this time In addition, future acts of terrorism and any possible reprisals as a consequence of action by the United States and its allies could be directed against companies operating in the United States Infrastructure and generation facilities such as Duke Energy's nuclear plants could be potential targets of terrorist activities The potential for terrorism has subjected Duke Energy's operations to increased risks and could have a material adverse effect on Duke Energy's business In particular, Duke Energy may experience increased capital and operating costs to implement increased security for its plants, including its nuclear power plants under the NRC's design basis threat requirements, such as additional physical plant security, additional security personnel or additional capability following a terrorist incident

The insurance industry has also been disrupted by these events As a result, the availability of insurance covering risks Duke Energy and Duke Energy's competitors typically insure against may decrease In addition, the insurance Duke Energy is able to obtain may have higher deductibles, higher premiums and more restrictive policy terms

Item 1B. Unresolved Staff Comments.

None

Table of Contents

PART I

Item 2. Properties.

U.S. FRANCHISED ELECTRIC AND GAS

As of December 31, 2006, U S Franchised Electric and Gas operated three nuclear generating stations with a combined net capacity of 5,020 MW (including a 12 5% ownership in the Catawba Nuclear Station), fifteen coal-fired stations with a combined net capacity of 13,552 MW, thirty-one hydroelectric stations (including two pumped-storage facilities) with a combined net capacity of 3,213 MW, fifteen CT stations with a combined net capacity of 5,245 MW and two CC stations with a combined net capacity of 560 MW The stations are located in North Carolina, South Carolina, Indiana, Ohio and Kentucky The MW displayed in the table below are based on summer capacity

Name	Gross MW	Net MW	Fuel	Location	Ownership Interest (percentage)
Carolinas:					
Oconee	2,538	2,538	Nuclear	SC	100%
Catawba	2,258	282	Nuclear	SC	12.5
Belews Creek	2,270	2,270	Coal	NC	100
McGuire	2,200	2,200	Nuclear	NC	100
Marshall	2,110	2,110	Coal	NC	100
Lincoln CT	1,267	1,267	Natural gas/Fuel oil	NC	100
Allen	1,145	1,145	Coal	NC	100
Bad Creek	1,360	1,360	Hydro	SC	100
Rockingham CT	825	825	Natural gas/Fuel oil	NC	100
Cliffside	760	760	Coal	NC	100
Jocassee	680	680	Hydro	SC	100
Riverbend	454	454	Coal	NC	100
Lee	370	370	Coal	SC	100
Buck	369	369	Coal	NC	100
Cowans Ford	325	325	Hydro	NC	100
Mill Creek CT	596	596	Natural gas/Fuel oil	SC	100
Dan River	276	276	Coal	NC	100
Buzzard Roost CT	196	196	Natural gas/Fuel oil	SC	100
Keowee	152	152	Hydro	SC	100
Riverbend CT	120	120	Natural gas/Fuel oil	NC	100
Buck CT	93	93	Natural gas/Fuel oil	NC	100
Lee CT	84	84	Natural gas/Fuel oil	SC	100
Dan River CT	85	85	Natural gas/Fuel oil	NC	100
Other small hydro (27 plants)	651	651	Hydro	NC/SC	100
Midwest:					
Gibson[(A)]	3,132	2,820	Coal	IN	100
Cayuga[(B)]	1,005	1,005	Coal/Fuel oil	IN	100
Wabash River[(C)]	676	676	Coal/Fuel oil	IN	100
East Bend	600	414	Coal	KY	69
Madison CT	596	596	Natural gas	OH	100
Gallagher	560	560	Coal	IN	100
Woodsdale CT	500	500	Natural gas/Propane	OH	100
Wheatland CT	460	460	Natural gas	IN	100
Noblesville CC	285	285	Natural gas	IN	100
Wabash River CC[(D)]	275	275	Syn Gas/Natural gas	IN	100
Miami Fort (Units 5 and 6)	163	163	Coal/Fuel oil	OH	100
Edwardsport	160	160	Coal	IN	100
Henry County CT	135	135	Natural gas	IN	100
Cayuga CT	106	106	Natural gas	IN	100
Miami Wabash CT	96	96	Fuel oil	IN	100
Connersville CT	86	86	Fuel oil	IN	100
Markland	45	45	Hydro	IN	100
Total	30,064	27,590			

Table of Contents

PART I

(A) Duke Energy Indiana owns and operates Gibson Station Units 1-4 and owns 50.05% of Unit 5, but is the operator

(B) Includes Cayuga Internal Combustion (IC)

(C) Includes Wabash River IC

(D) Included in Assets Held for Sale

In addition, as of December 31, 2006, U S Franchised Electric and Gas owned approximately 20,700 conductor miles of electric transmission lines, including 600 miles of 525 kilovolts, 1,700 miles of 345 kilovolts, 3,300 miles of 230 kilovolts, 8,800 miles of 100 to 161 kilovolts, and 6,300 miles of 13 to 69 kilovolts U S Franchised Electric and Gas also owned approximately 146,700 conductor miles of electric distribution lines, including 102,900 miles of overhead lines and 43,800 miles of underground lines, as of December 31 2006 and approximately 8,900 miles of gas mains and service lines As of December 31, 2006, the electric transmission and distribution systems had approximately 2,300 substations U S Franchised Electric and Gas also owns three underground caverns with a total storage capacity of approximately 23 million gallons of liquid propane This liquid propane is used in the three propane/air peak shaving plants located in Ohio and Kentucky Propane/air peak shaving plants store propane and, when needed, vaporize the propane and mix with natural gas to supplement the natural gas supply during peak demand periods and emergencies

Substantially all of Duke Energy Carolinas' electric plant in service is mortgaged under the indenture relating to Duke Energy's various series of First and Refunding Mortgage Bonds

(For a map showing U S Franchised Electric and Gas' properties, see "Business—U S Franchised Electric and Gas" earlier in this section.)

NATURAL GAS TRANSMISSION

As discussed in Item 1 "Business", effective January 2, 2007, Duke Energy consummated the spin-off of its natural gas businesses, which includes the Natural Gas Transmission segment, to shareholders

Texas Eastern's gas transmission system extends approximately 1,700 miles from producing fields in the Gulf Coast region of Texas and Louisiana to Ohio, Pennsylvania, New Jersey and New York It consists of two parallel systems, one with three large-diameter parallel pipelines and the other with one to three large-diameter pipelines Texas Eastern's onshore system consists of approximately 8,600 miles of pipeline and 73 compressor stations

Texas Eastern also owns and operates two offshore Louisiana pipeline systems, which extend approximately 100 miles into the Gulf of Mexico and include approximately 500 miles of Texas Eastern's pipeline system and has an ownership interest in a processing plant in Southern Louisiana

Texas Eastern has two joint-venture storage facilities in Pennsylvania and one wholly owned and operated storage field in Maryland Texas Eastern's total working capacity in these three fields is 75 Bcf

Algonquin connects with Texas Eastern's facilities in New Jersey, and extends approximately 250 miles through New Jersey, New York, Connecticut, Rhode Island and Massachusetts where it connects to Maritimes & Northeast Pipeline The system consists of approximately 1,100 miles of pipeline with six compressor stations

ETNG's transmission system crosses Texas Eastern's system at two points in Tennessee and consists of two mainline systems totaling approximately 1,400 miles of pipeline in Tennessee, Georgia, North Carolina and Virginia, with 18 compressor stations ETNG has an LNG storage facility in Tennessee with a total working capacity of 1 2 Bcf East Tennessee also connects to Saltville Gas Storage Company and Virginia Gas Storage Company These natural gas storage fields are located in the state of Virginia and have a working gas capacity of approximately 5 Bcf

Maritimes & Northeast Pipeline, LLC and Maritimes & Northeast Pipeline, LP (collectively, Maritimes & Northeast) transmission system (approximately 78% owned by Duke Energy) extends approximately 900 miles from producing fields in Nova Scotia through New Brunswick, Maine, New Hampshire and Massachusetts, connecting to Algonquin in Beverly, Massachusetts It has two compressor stations on the system

The British Columbia Pipeline System consists of two divisions The field services division operates more than 1,840 miles of gathering pipelines in British Columbia, Alberta, the Yukon Territory and the Northwest Territories, as well as 22 field compressor stations; four gas processing plants located in British Columbia near Fort Nelson, Taylor, Chetwynd and in the Sikanni area Northwest of Fort St John, and three elemental sulphur recovery plants located at Fort Nelson, Taylor and Chetwynd Total contractible capacity is approximately 2 0 Bcf of residue gas per day The pipeline division has approximately 1,740 miles of transmission pipelines in British Columbia and Alberta, as well as 18 mainline compressor stations

PART I

The Empress system is a collection of midstream assets involved in the extraction, storage, transportation, distribution and marketing of NGLs in Canada and the U S Assets include, among other things, an ownership interest in an NGL extraction plant on the TransCanada Alberta system, a liquids transmission pipeline, seven terminals along the pipe, two storage facilities, a fractionation facility, and an integrated NGL marketing and gas supply business Total processing capacity of the Empress system is 2 4 Bcf of gas per day The Empress system is located in Western Canada

The DEGT Midstream operations are located in Western Canada and include thirteen natural gas processing plants and over 1,000 miles of natural gas gathering pipelines located in Western Canada

Union Gas owns and operates natural gas transmission, distribution and storage facilities in Ontario Union Gas' distribution system consists of approximately 22,000 miles of distribution pipelines Union Gas' underground natural gas storage facilities have a working capacity of approximately 150 Bcf in 20 underground facilities located in depleted gas fields Its transmission system consists of approximately 3,000 miles of pipeline and six mainline compressor stations

MHP owns and operates two natural gas storage facilities, Moss Bluff and Egan, with a total storage capacity of approximately 31 Bcf The Moss Bluff facility consists of three storage caverns located in Southeast Texas and has access to five pipeline systems The Egan facility consists of three storage caverns located in South Central Louisiana and has access to eight pipeline systems

Natural Gas Transmission also has a 50 percent investment in Gulfstream Natural Gas System, LLC (Gulfstream), a 691-mile interstate natural gas pipeline system owned and operated ~~jointly by Duke Energy and The Williams Company, Inc.~~

(For a map showing natural gas transmission and storage properties, see "Business—Natural Gas Transmission" earlier in this section)

FIELD SERVICES

(For information and a map showing Field Services' properties, see "Business—Field Services" earlier in this section)

COMMERCIAL POWER

The following table provides information about Commercial Power's merchant generation portfolio as of December 31, 2006 The MW displayed in the table below are based on summer capacity

Name	Gross MW	Net MW	Plant Type	Primary Fuel	Location	Approximate Ownership Interest (percentage)
Hanging Rock	1,240	1,240	Combined Cycle	Natural gas	OH	100
Lee	640	640	Simple Cycle	Natural gas	IL	100
Vermillion	640	480	Simple Cycle	Natural gas	IN	75
Fayette	620	620	Combined Cycle	Natural gas	PA	100
Washington	620	620	Combined Cycle	Natural gas	OH	100
Dick's Creek	152	152	Simple Cycle	Natural gas	OH	100
Beckjord CT	212	212	Simple Cycle	Fuel oil	OH	100
Miami Fort CT	60	60	Simple Cycle	Fuel oil	OH	100
Miami Fort (Units 7 and 8)(1)	1,080	720	Steam	Coal	OH	64
W.C. Beckjord(1)	1,124	862	Steam	Coal	OH	37.5
W.M. Zimmer(1)	1,300	605	Steam	Coal	OH	46.5
J.M. Stuart	2,340	912	Steam	Coal	OH	39
Killen(1)	600	198	Steam	Coal	OH	33
Conesville(1)	780	312	Steam	Coal	OH	40
Brownsville	466	466	Simple Cycle	Natural gas	TN	100
Total	11,874	8,099				

(1) Commercial Power generation facilities are jointly owned by Duke Energy Ohio and subsidiaries of American Electric Power, Inc and Dayton Power and Light, Inc

(For a map showing Commercial Power's properties, see "Business—Commercial Power" earlier in this section)

Table of Contents

PART I

INTERNATIONAL ENERGY

The following table provides information about International Energy's generation portfolio in continuing operations as of December 31, 2006

Name	Gross MW	Net MW	Fuel	Location	Approximate Ownership Interest (percentage)
Paranapanema	2,307	2,112	Hydro	Brazil	95%
Hidroelectrica Cerros Colorados	576	523	Hydro/Natural Gas	Argentina	91
Egenor	509	508	Hydro/Diesel	Peru	100
DEI Guatemala	250	250	Fuel Oil/Diesel	Guatemala	100
DEI El Salvador	291	263	Fuel Oil/Diesel	El Salvador	90
Electroquil	181	149	Diesel	Ecuador	82
Aguaytia	177	117	Natural Gas	Peru	66
Empresa Electrica Corani	147	74	Hydro	Bolivia	50
Total	4,438	3,996			

In December 2006, Duke Energy engaged in discussions with a potential buyer of International Energy's assets in Bolivia. Such discussions to sell the assets were subject to a binding agreement between the parties, which was finalized in February 2007, and resulted in the sale of International Energy's 50 percent ownership interest in two hydroelectric power plants near Cochabamba, Bolivia to Econergy International

International Energy also owns a 25% equity interest in NMC In 2006, the NMC produced approximately 850 thousand metric tons of methanol and 1 million metric tons of MTBE In addition, International Energy owns a 50% equity interest in the Campeche natural gas processing and compression facility Campeche has an installed processing capacity of 270 MMcf/d International Energy also owns a 25% equity interest in Attiki, which is a natural gas distributor that has an exclusive 30 year license to supply natural gas to residential and commercial customers within the geographical area of Athens, Greece (For additional information and a map showing International Energy's properties, see "Business—International Energy" earlier in this section)

CRESCENT

(For information regarding Crescent's properties, see "Business—Crescent" earlier in this section)

OTHER

(For information regarding the properties of the business unit now known as Other, see "Business—Other" earlier in this section)

Item 3. Legal Proceedings.

For information regarding legal proceedings, including regulatory and environmental matters, see Note 4 to the Consolidated Financial Statements, "Regulatory Matters" and Note 17 to the Consolidated Financial Statements, "Commitments and Contingencies—Litigation" and "Commitments and Contingencies—Environmental "

Table of Contents

PART I

Item 4. Submission of Matters to a Vote of Security Holders.

At the Duke Energy Corporation Annual Meeting of Shareholders on October 24, 2006, shareholders elected Roger Agnelli, Paul M Anderson, William Barnet, III, G Alex Bernhardt, Sr , Michael G Browning, Phillip R Cox, William T Esrey, Ann Maynard Gray, James H Hance, Jr , Dennis R Hendrix, Michael E J Phelps, James T Rhodes, James E Rogers, Mary L Schapiro and Dudley S Taft to serve as directors until the next annual meeting of shareholders and until such Director's successor is duly elected and qualified Below is a tabulation of votes with respect to each nominee for director at the meeting:

Nominee	For	Against/Withheld
Roger Agnelli	947,929,162	155,182,625
Paul M Anderson	1,075,040,338	28,071,449
William Barnet, III	1,079,646,448	23,465,339
G Alex Bernhardt, Sr	1,075,727,658	27,384,129
Michael G. Browning	1,072,347,645	30,764,142
Phillip R. Cox	1,064,593,023	38,518,764
William T. Esrey	1,073,809,374	29,302,413
Ann Maynard Gray	1,068,607,394	34,504,393
James H. Hance, Jr.	1,072,614,825	30,496,962
Dennis R Hendrix	1,072,182,705	30,929,082
Michael E. J. Phelps	752,240,344	350,871,443
James T. Rhodes	1,079,877,900	23,233,887
James E. Rogers	1,074,300,198	28,811,589
Mary L. Schapiro	1,076,085,064	27,026,723
Dudley S. Taft	1,062,145,116	40,966,671

In addition, shareholders at the meeting also approved the Duke Energy Corporation 2006 Long-Term Incentive Compensation Plan There were 750,402,214 shares voted for the plan, 88,378,012 shares voted against the plan, and 15,211,175 shares abstained

And, shareholders at the meeting also ratified the selection of Deloitte & Touche LLP to act as independent auditors for Duke Energy Corporation for 2006 There were 1,072,065,312 shares voted for the proposal, 20,828,427 shares voted against the proposal and 10,218,046 shares abstained

PART II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities.

Duke Energy's common stock is listed for trading on the New York Stock Exchange As of February 23, 2007, there were approximately 175,252 common stockholders of record

Common Stock Data by Quarter

	2006			2005		
		Stock Price Range[a]			Stock Price Range[a]	
	Dividends Per Share	High	Low	Dividends Per Share	High	Low
First Quarter	$ 0.31	$ 29.77	$ 27.38	$ 0.275	$ 28.20	$ 24.37
Second Quarter[b]	0 63	29.85	26 94	0 585	29.98	27 34
Third Quarter	—	30.98	28.84	—	30.55	27.84
Fourth Quarter[b]	0 32	34 50	29 82	0 310	29 35	25 06

(a) Stock prices represent the intra-day high and low stock price

(b) Dividends paid in September 2006 and December 2006 were increased from $0 31 per share to $0 32 per share

On January 2, 2007, Duke Energy consummated the spin-off of the natural gas businesses to shareholders In connection with this transaction, Duke Energy distributed all the shares of common stock of Spectra Energy to Duke Energy shareholders The distribution ratio approved by Duke Energy's Board of Directors was one-half share of Spectra Energy common stock for every share of Duke Energy common stock Subsequent to the distribution, the market price of Duke Energy common stock was significantly less than the 2006 trading ranges above due to the fact that a proportionate share of the value of Duke Energy stock prior to the spin-off was transferred to Spectra Energy Additionally, future dividends paid on Duke Energy common stock are expected to be less than the 2006 dividend of $1 26 per share as dividends are anticipated to be split proportionately between Duke Energy and Spectra Energy such that the sum of the dividends of the two stand-alone companies approximates the former total dividend of Duke Energy Duke Energy expects to continue its policy of paying regular cash dividends, although there is no assurance as to the amount of future dividends because they depend on future earnings, capital requirements, and financial condition Future dividends are subject to declaration by the Board of Directors

Issuer Purchases of Equity Securities for Fourth Quarter of 2006

None

Duke Energy previously announced plans to execute up to approximately $2 5 billion in common stock repurchases over a three year period On May 9, 2005, Duke Energy announced plans to suspend additional repurchases under the open-market purchase plan, pending further assessment, primarily due to the merger with Cinergy At the time of suspension, Duke Energy had repurchased 32.6 million shares of common stock for approximately $0.9 billion During the first quarter of 2006, Duke Energy announced the commencement of up to $1 billion of additional share repurchases under the previously announced plan During the first six months of 2006, Duke Energy repurchased approximately 17 5 million shares of common stock for approximately $0.5 billion In June 2006, in connection with the plan to spin off Duke Energy's natural gas businesses to Duke Energy shareholders, the share repurchase program was suspended At the time of suspension, Duke Energy had repurchased approximately 50 million shares of common stock for approximately $1 4 billion under this repurchase plan. In October 2006, Duke Energy's Board of Directors authorized the reactivation of the share repurchase plan for Duke Energy of up to $500 million of share repurchases after the spin-off of the natural gas businesses has been completed As of December 31, 2006, the dollar value of shares that may yet be purchased under the plan is approximately $1 1 billion

PART II

Item 6. Selected Financial Data.[a]

	2006	2005	2004	2003[c]	2002
	(in millions, except per-share amounts)				
Statement of Operations					
Operating revenues	$ 15,184	$ 16,297	$ 19,596	$ 17,623	$ 14,757
Operating expenses	12,493	13,416	16,441	16,632	12,313
Gains on sales of investments in commercial and multi-family real estate	201	191	192	84	106
Gains (losses) on sales of other assets and other, net	276	534	(416)	(199)	32
Operating income	3,168	3,606	2,931	876	2,582
Other income and expenses, net	1,008	1,809	304	550	352
Interest expense	1,253	1,066	1,282	1,331	1,116
Minority interest expense	61	538	200	62	91
Earnings from continuing operations before income taxes	2,862	3,811	1,753	33	1,727
Income tax expense (benefit) from continuing operations	843	1,282	507	(52)	544
Income from continuing operations	2,019	2,529	1,246	85	1,183
(Loss) income from discontinued operations, net of tax	(156)	(701)	244	(1,246)	(149)
Income (loss) before cumulative effect of change in accounting principle	1,863	1,828	1,490	(1,161)	1,034
Cumulative effect of change in accounting principle, net of tax and minority interest	—	(4)	—	(162)	—
Net income (loss)	1,863	1,824	1,490	(1,323)	1,034
Dividends and premiums on redemption of preferred and preference stock	—	12	9	15	13
Earnings (loss) available for common stockholders	$ 1,863	$ 1,812	$ 1,481	$ (1,338)	$ 1,021
Ratio of Earnings to Fixed Charges[d]	3.2	4.7	2.3	—[b]	2.0
Common Stock Data					
Shares of common stock outstanding[e]					
Year-end	1,257	928	957	911	895
Weighted average—basic	1,170	934	931	903	836
Weighted average—diluted	1,188	970	966	904	838
Earnings per share (from continuing operations)					
Basic	$ 1.73	$ 2.69	$ 1.33	$ 0.09	$ 1.41
Diluted	1.70	2.60	1.29	0.09	1.41
(Loss) earnings per share (from discontinued operations)					
Basic	$ (0.14)	$ (0.75)	$ 0.26	$ (1.39)	$ (0.19)
Diluted	(0.13)	(0.72)	0.25	(1.39)	(0.19)
Earnings (loss) per share (before cumulative effect of change in accounting principle)					
Basic	$ 1.59	$ 1.94	$ 1.59	$ (1.30)	$ 1.22
Diluted	1.57	1.88	1.54	(1.30)	1.22
Earnings (loss) per share					
Basic	$ 1.59	$ 1.94	$ 1.59	$ (1.48)	$ 1.22
Diluted	1.57	1.88	1.54	(1.48)	1.22
Dividends per share	1.26	1.17	1.10	1.10	1.10
Balance Sheet					
Total assets	$ 68,700	$ 54,723	$ 55,770	$ 57,485	$ 60,122
Long-term debt including capital leases, less current maturities	$ 18,118	$ 14,547	$ 16,932	$ 20,622	$ 20,221

(a) Significant transactions reflected in the results above include: 2006 merger with Cinergy (see Note 2 to the Consolidated Financial Statements, "Acquisitions and Dispositions"), 2006 Crescent joint venture transaction and subsequent deconsolidation effective September 7, 2006 (see Note 2 to the Consolidated Financial Statements, "Acquisitions and Dispositions), 2005 DENA disposition (see Note 13 to the Consolidated Financial Statements, "Discontinued Operations and Assets Held for Sale"), 2005 deconsolidation of DEFS effective July 1, 2005 (see Note 2 to the Consolidated Financial Statements, "Acquisitions and Dispositions"), 2005 DEFS sale of TEPPCO (see Note 2 to the Consolidated Financial Statements, "Acquisitions and Dispositions") and 2004 DENA sale of the Southeast plants (see Note 2 to the Consolidated Financial Statements, "Acquisitions and Dispositions")

(b) Earnings were inadequate to cover fixed charges by $241 million for the year ended December 31, 2003

(c) As of January 1, 2003, Duke Energy adopted the remaining provisions of Emerging Issues Task Force (EITF) 02-03, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and for Contracts Involved in Energy Trading and Risk Management Activities" (EITF 02-03) and SFAS No 143, "Accounting for Asset Retirement Obligations" (SFAS No 143). In accordance with the transition guidance for these standards. Duke Energy recorded a net-of-tax and minority interest cumulative effect adjustment for change in accounting principles (See Note 1 to the Consolidated Financial Statements, "Summary of Significant Accounting Policies," for further discussion)

(d) Includes pre-tax gains of approximately $0.9 billion, net of minority interest, related to the sale of TEPPCO GP and LP in 2005 (see Note 2 to the Consolidated Financial Statements, "Acquisitions and Dispositions").

(e) 2006 increase primarily attributable to issuance of approximately 313 million shares in connection with Duke Energy's merger with Cinergy (see Note 2 to the Consolidated Financial Statements, "Acquisitions and Dispositions")

Table of Contents

PART II

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

INTRODUCTION

Management's Discussion and Analysis should be read in conjunction with the Consolidated Financial Statements and Notes for the years ended December 31, 2006, 2005 and 2004.

EXECUTIVE OVERVIEW

2006 Objectives. Duke Energy's objectives for 2006, as outlined in the 2006 Charter, consisted of the following:

- Establish an industry-leading electric power platform through successful execution of the merger with Cinergy;
- Deliver on the 2006 financial objectives and position Duke Energy for growth in 2007 and beyond;
- Complete the exit of the former DENA business and pursue strategic portfolio opportunities;
- Build a high-performance culture focused on safety, diversity and inclusion, employee development, leadership and results; and
- Build credibility through leadership on key policy issues, transparent communications and excellent customer service.

During 2006, management executed on its objectives primarily through strategically completed and pending acquisitions, as well as dispositions of certain businesses with higher risk profiles, such as the former DENA operations outside the Midwest and the Cinergy commercial marketing and trading businesses. During 2006, Duke Energy created a business model that would give both Duke Energy's electric and gas businesses stand-alone strength and additional scope and scale along with steady and stable earnings growth.

On April 3, 2006, Duke Energy and Cinergy consummated the previously announced merger, which combined the Duke Energy and Cinergy regulated franchises as well as deregulated generation in the Midwestern United States. The merger with Cinergy increased the size and scope of Duke Energy's electric utility operations. Duke Energy management expects to achieve numerous synergies, both immediately and over time, in all regions impacted by the merger.

As a result of the additional size and scope of the electric utility operations discussed above, in June 2006, the Board of Directors of Duke Energy authorized management to pursue a plan to create two separate publicly traded companies by spinning off Duke Energy's natural gas businesses to Duke Energy shareholders, which was completed on January 2, 2007. The new natural gas company, Spectra Energy, consists of Duke Energy's Natural Gas Transmission business segment, including Union Gas, as well as Duke Energy's 50-percent ownership interest in DEFS. The spin off of the natural gas business is expected to deliver long-term value to shareholders as the two stand-alone companies are expected to be able to more easily participate in growth opportunities in their own industries as well as the gas and power industry consolidations.

In connection with the effort to reduce the risk profile of Duke Energy and to focus on businesses that can be expected to contribute steady, stable earnings growth, during 2006 Duke Energy finalized the sale of the former DENA power generation fleet outside of the Midwest to LS Power and the sale of the Cinergy commercial marketing and trading business to Fortis, a Benelux-based financial services group (Fortis).

Additionally, the Board of Directors of Duke Energy authorized management to explore the potential value of bringing in a joint venture partner at Crescent to expand the business and create a platform for increased growth. On September 7, 2006, an indirect wholly owned subsidiary of Duke Energy closed an agreement to create the Crescent JV with MS Members. As a result of the Crescent transaction, Duke Energy no longer controls the Crescent JV and on September 7, 2006 deconsolidated its investment in Crescent and subsequently accounts for its investment in the Crescent JV utilizing the equity method of accounting.

After completion of the spin-off of the natural gas businesses, the primary businesses remaining in Duke Energy in 2007 are the U.S. Franchised Electric and Gas business segment, the Commercial Power business segment, the International Energy business segment and Duke Energy's effective 50% interest in the Crescent JV, which management currently expects to continue to be a reportable business segment.

Duke Energy announced an agreement with Southern Company to evaluate the potential construction of a new nuclear power plant at a site jointly owned in Cherokee County, South Carolina. Additionally, Duke Energy continues to evaluate other opportunities to re-invest in the electric utility operations, by modernizing older coal-fired plants in the Carolinas and exploring the replacement of an aging coal plant in Indiana with a coal gasification plant. Also, during the fourth quarter of 2006, Duke Energy closed on a transaction to acquire from Dynegy a 825 megawatt power plant located in Rockingham County, North Carolina. This peaking plant, which will primarily be used during times of high electricity demand, generally in the winter and summer months, will provide customers with competitively priced peaking capacity and helps to ensure Duke Energy can meet growing customer demands for electricity in the foreseeable future. Additionally, in

December 2006 Duke Energy entered into an agreement to increase its ownership interest in the Catawba Nuclear Station for a purchase price of approximately $158 million The purchase is subject to regulatory approvals and other conditions precedent and is expected to close prior to September 30, 2008.

Effective with the third quarter 2006, the Board of Directors of Duke Energy approved a quarterly dividend increase of $0 01 per share, increasing the annual dividend to $1 28 per share Additionally, during 2006 Duke Energy repurchased approximately 17 5 million shares of its common stock for approximately $500 million In connection with the above mentioned plan to spin off Duke Energy's natural gas businesses to Duke Energy shareholders, the share repurchase program was suspended In October 2006, Duke Energy's Board of Directors authorized the reactivation of the share repurchase plan for Duke Energy of up to $500 million of share repurchases subsequent to the spin-off of the natural gas businesses on January 2, 2007

2006 Financial Results For the year-ended December 31. 2006, Duke Energy reported earnings available for common stockholders of $1,863 million and basic and diluted earnings per share (EPS) of $1 59 and $1 57, respectively, as compared to reported earnings available for common stockholders of $1,812 million and basic and diluted EPS of $1 94 and $1 88, respectively, for the year-ended December 31, 2005 Earnings available for common stockholders for 2006 as compared to 2005 were fairly flat; however, basic and diluted EPS were negatively impacted by the issuance of approximately 313 million shares in April 2006 in connection with the Cinergy merger The highlights for 2006 include the following:

- U S Franchised Electric and Gas experienced higher earnings in 2006 primarily as a result of the addition of the former Cinergy regulated utility operations in the Midwest. These higher results were partially offset by milder weather, the impact of rate reductions related to Cinergy merger approvals, and lower bulk power marketing results in the Carolinas
- Natural Gas Transmission's results were flat from 2005 to 2006, but were affected by strong commodity prices related to processing activities and higher operating and maintenance expenses
- Field Services experienced lower earnings in 2006 primarily as a result of the 2005 gains on the sale of the TEPPCO investments and the transfer of a 19 7 percent interest in DEFS to ConocoPhillips in July 2005, which resulted in the deconsolidation of the investment in DEFS Results in 2006 were favorably affected by strong commodity prices
- Commercial Power experienced higher earnings in 2006 primarily as a result of the addition of the former Cinergy non-regulated generation operations in the Midwest, partially offset by the impacts of unfavorable purchase accounting charges as a result of recognizing the Cinergy assets and liabilities at their estimated fair values as of the date of merger
- International Energy experienced lower earnings in 2006 primarily as a result of 2006 non-cash charges related to a settlement related to the Citrus litigation, an impairment charge related to the investment in Campeche, and an impairment charge related to the sale of Bolivian assets
- Crescent experienced higher earnings in 2006 primarily as a result of the gain recognized on the joint venture transaction in September 2006, which resulted in the deconsolidation of Duke Energy's investment in the Crescent JV
- Other experienced higher losses in 2006 primarily as a result of 2006 charges related to contract settlement negotiations, and costs to achieve the Cinergy merger and the spin-off of the natural gas businesses
- Income tax expense from continuing operations was lower in 2006 as a result of a decrease in earnings from continuing operations before income taxes and a reduction in the effective tax rate The reduction in the effective tax rate was primarily a result of favorable tax settlements on research and development costs and nuclear decommissioning costs, tax benefits related to the impairment of the investment in Bolivia, and tax credits recognized on synthetic fuel operations
- During 2006, Duke Energy recognized net of tax losses of $156 million in discontinued operations, as compared to net of tax losses of $701 million in 2005 During 2006, Duke Energy completed the exit of the former DENA operations outside the Midwest region and recognized additional losses as a result of sales of certain contracts Additionally, during 2006 Duke Energy exited the Cinergy commercial marketing and trading business

2007 Objectives As a result of the initiatives accomplished during 2006 and the spin-off of the natural gas businesses on January 2, 2007, Duke Energy is positioned as a lower-risk business with steady earnings growth potential For 2007, management of Duke Energy is focused on the following objectives, as outlined in the 2007 Charter:

- Establish the identity and culture of the new Duke Energy, unifying its people, values, strategy, processes and systems;
- Optimize its operations by focusing on safety, simplicity, accountability, inclusion, customer satisfaction, cost management and employee development.

PART II

- Achieve public policy, regulatory and legislative outcomes that balance customers' needs for reliable energy at competitive prices with shareholders' expectation of superior returns;
- Invest in energy infrastructure that meets rising customer demands for reliable energy in an energy efficient and environmentally sound manner; and
- Achieve 2007 financial objectives and position Duke Energy to meet future growth targets

Duke Energy's consolidated earnings during 2007 are anticipated to be reduced principally as a result of the spin-off of the natural gas businesses on January 2, 2007 Excluding the impacts of the spin-off of the natural gas businesses, earnings are anticipated to be favorably affected by the following factors: a full year of earnings from the Midwest operations acquired from Cinergy, realization of cost savings as the regulatory rate reductions shared with ratepayers will phase-out in 2007, customer sales growth, capital reinvestments and regulatory initiatives.

The majority of expected earnings in 2007 are anticipated to be contributed from U S Franchised Electric and Gas, which consists of Duke Energy's regulated businesses operating a net capacity of approximately 28,000 megawatts of generation. The regulated generation portfolio consists of a mix of coal, nuclear, natural gas and hydroelectric generation, with substantially all of the sales of electricity coming from coal and nuclear generation facilities Commercial Power has net capacity of approximately 8,100 megawatts of unregulated generation, of which approximately 4,100 megawatts serves retail customers under the Rate Stabilization Plan in Ohio Approximately 75% of International Energy's net capacity of approximately 4,000 megawatts of installed generation capacity in Latin America consists of baseload hydroelectric capacity that carries a low level of dispatch risk; in addition, for 2007 over 90% of International Energy's contractible capacity in Latin America is either currently contracted or receives a system capacity payment

Duke Energy's total dividends and dividends per share in 2007 will be lower than in 2006 as a result of the spin-off of the natural gas businesses on January 2, 2007 Future dividends are expected to grow in connection with any earnings growth.

During the three-year period from 2007 to 2009, Duke Energy anticipates annual capital expenditures of approximately $3 5 billion, for a total of approximately $10 billion These expenditures are principally related to expansion plans, environmental spending related to Clean Air requirements, nuclear fuel, as well as maintenance costs Current estimates are that Duke Energy's regulated generation capacity will need to increase by approximately 6,400 megawatts over the next ten years, with the majority being in North and South Carolina and the remainder being in Indiana Duke Energy is committed to adding base load capacity at a reasonable price while modernizing the current generation facilities by replacing older, less efficient plants with cleaner, more efficient plants Significant expansion projects may include a new IGCC plant in Indiana, a new coal unit (or units) at Duke Energy's existing Cliffside facility in North Carolina, new gas-fired generation units and costs related to the evaluation of the potential construction of a new nuclear power plant in Cherokee County, South Carolina as well as normal additions due to system growth Costs related to environmental spending are expected to decrease over the three-year period as the upgrades to comply with the new environmental regulations are completed Duke Energy does not anticipate any additional capital investment related to its investment in the Crescent JV Duke Energy does not currently anticipate funding 2007 capital expenditures with the issuance of common equity, but rather through the use of available cash and cash equivalents as well as the issuance of incremental debt

As the majority of Duke Energy's anticipated future capital expenditures are related to its regulated operations, a significant risk to Duke Energy is the ability to recover in a timely manner costs related to such expansion In Indiana, Duke Energy has been given approval to recover its development costs for the new IGCC plant In North and South Carolina, Duke Energy will pursue legislation to provide for construction work in progress recovery for the additional unit (or units) at the Cliffside facility as well as the proposed nuclear power plant Additionally, Duke Energy is attempting to obtain assurance of recovery of development costs related to the proposed nuclear power plant Duke Energy does not anticipate beginning construction of the proposed nuclear power plant without adequate assurance of cost recovery from the state legislators or regulators In November 2006, Duke Energy received approval for nearly $260 million of future federal tax credits related to costs to be incurred for the modernization of the Cliffside facility as well as the IGCC plant in Indiana

In an effort to respond to concerns over climate change, the U.S Congress recently discussed various proposals to reduce or cap carbon dioxide and other greenhouse gas emissions Any legislation enacted as a result of these efforts could involve a market based cap and trade program Duke Energy is also focusing on energy efficiency initiatives in an effort to reduce emissions

Duke Energy's current regulatory initiatives primarily include obtaining the timely recovery of invested capital and pursuing a regulatory extension of the Rate Stabilization Plan in Ohio through 2010 as well as being a proponent of cost-effective energy efficiency initiatives In North Carolina, Duke Energy is required by June 1, 2007 to file a rate case or show that a price adjustment is not required During 2006, Duke Energy filed for an increase in its base electric rates in Kentucky In December 2006, the Kentucky Public Service Commission approved an annual rate increase of $49 million to be effective January 1, 2007

New energy legislation has been introduced in the current South Carolina legislative session which includes expansion of the annual fuel clause mechanism to include recovery of costs of reagents (ammonia, limestone, etc) that are consumed in the operation of Duke Energy Carolina's SO_2 and NOx control technologies The legislation also includes provisions to provide cost recovery assurance for upfront development costs associated with nuclear baseload generation, cost recovery assurance for construction costs associated with nuclear or coal baseload generation, and the ability to recover financing costs for new nuclear or coal baseload generation through annual riders Similar legislation is being discussed in North Carolina and may be introduced in the 2007 legislative session

In summary, Duke Energy is coordinating its future capital expenditure requirements with regulatory initiatives in order to ensure adequate and timely cost recovery while continuing to provide low cost energy to its customers

Economic Factors for Duke Energy's Business. Duke Energy's business model provides diversification between stable, less cyclical businesses like U S Franchised Electric and Gas, and the traditionally higher-growth and more cyclical energy businesses like Commercial Power and International Energy Additionally, Crescent's portfolio strategy is diversified between residential, commercial and multi-family development All of Duke Energy's businesses can be negatively affected by sustained downturns or sluggishness in the economy, including low market prices of commodities, all of which are beyond Duke Energy's control, and could impair Duke Energy's ability to meet its goals for 2007 and beyond

Declines in demand for electricity as a result of economic downturns would reduce overall electricity sales and lessen Duke Energy's cash flows, especially as industrial customers reduce production and, thus, consumption of electricity A portion of U S Franchised Electric and Gas' business risk is mitigated by its regulated allowable rates of return and recovery of fuel costs under fuel adjustment clauses

If negative market conditions should persist over time and estimated cash flows over the lives of Duke Energy's individual assets do not exceed the carrying value of those individual assets, asset impairments may occur in the future under existing accounting rules and diminish results of operations A change in management's intent about the use of individual assets (held for use versus held for sale) or a change in fair value of assets held for sale could also result in impairments or losses

Duke Energy's 2007 goals can also be substantially at risk due to the regulation of its businesses Duke Energy's businesses in the United States are subject to regulations on the federal and state level Regulations, applicable to the electric power industry, have a significant impact on the nature of the businesses and the manner in which they operate Changes to regulations are ongoing and Duke Energy cannot predict the future course of changes in the regulatory environment or the ultimate effect that any future changes will have on its business

Duke Energy's earnings are impacted by fluctuations in commodity prices Exposure to commodity prices generates higher earnings volatility in the unregulated businesses as there are timing differences as to when such costs are recovered in rates To mitigate these risks, Duke Energy enters into derivative instruments to effectively hedge known exposures With the 2006 sales of former DENA's assets outside the Midwestern United States, including substantially all the derivative portfolio, and Cinergy's marketing and trading operation, Duke Energy expects a less volatile earnings pattern going forward

Additionally, Duke Energy's investments and projects located outside of the United States expose Duke Energy to risks related to laws of other countries, taxes, economic conditions, fluctuations in currency rates, political conditions and policies of foreign governments Changes in these factors are difficult to predict and may impact Duke Energy's future results

Duke Energy also relies on access to both short-term money markets and longer-term capital markets as a source of liquidity for capital requirements not met by cash flow from operations An inability to access capital at competitive rates could adversely affect Duke Energy's ability to implement its strategy Market disruptions or a downgrade of Duke Energy's credit rating may increase its cost of borrowing or adversely affect its ability to access one or more sources of liquidity

For further information related to management's assessment of Duke Energy's risk factors, see Item 1A "Risk Factors "

RESULTS OF OPERATIONS

Consolidated Operating Revenues

Year Ended December 31, 2006 as Compared to December 31, 2005 Consolidated operating revenues for 2006 decreased $1,113 million, compared to 2005 This change was driven by:

- A $5,530 million decrease due to the deconsolidation of DEFS, effective July 1, 2005, and
- A $274 million decrease at Crescent due primarily to the deconsolidation of Crescent, effective September 7, 2006 and softening in the residential real estate market

Partially offsetting these decreases in revenues were:

- An approximate $3,891 million increase due to the merger with Cinergy
- A $468 million increase at Natural Gas Transmission due primarily to Canadian assets (approximately $281 million), primarily higher processing revenues on the Empress System, favorable Canadian dollar foreign exchange impacts (approximately $157 million), and recovery of higher natural gas commodity costs (approximately $146 million), resulting from higher natural gas prices passed through to customers without a mark-up at Union Gas, partially offset by lower gas usage due to unseasonably warmer weather (approximately $186 million)
- A $216 million increase at International Energy due primarily to higher revenues in Peru from increased ownership and resulting consolidation of Aguaytia (approximately $118 million), higher energy prices in El Salvador (approximately $40 million), favorable results in Brazil, primarily foreign exchange rate impacts (approximately $31 million) and higher electricity volumes and prices in Argentina (approximately $27 million), and
- An approximate $130 million increase in Other related to the prior year impact of mark-to-market losses, primarily unrealized, due to increased commodity prices as a result of the discontinuance of certain cash flow hedges entered into to hedge Field Services' commodity price risk (see Note 8 to the Consolidated Financial Statements, "Risk Management and Hedging Activities, Credit Risk, and Financial Instruments") from February 22, 2005 to June 30, 2005 Effective with the deconsolidation of DEFS on July 1, 2005, mark-to-market changes related to these discontinued hedges are classified in Other income and expenses, net on the Consolidated Statements of Operations.

Year Ended December 31, 2005 as Compared to December 31, 2004. Consolidated operating revenues for 2005 decreased $3,299 million, compared to 2004. This change was driven by:

- A $5,380 million decrease due to the deconsolidation of DEFS, effective July 1, 2005, and
- An approximate $130 million decrease resulting from mark-to-market losses, primarily unrealized, due to increased commodity prices as a result of the discontinuance of certain cash flow hedges entered into to hedge Field Services' commodity price risk discussed above

Partially offsetting these decreases in revenues were

- An approximate $850 million increase at Field Services, excluding the impact of the deconsolidation of DEFS, due primarily to higher average commodity prices, primarily NGL and natural gas in the first six months of 2005
- A $704 million increase at Natural Gas Transmission due primarily to new Canadian assets (approximately $269 million), primarily the Empress System, favorable foreign exchange rates (approximately $153 million) as a result of the strengthening Canadian dollar (partially offset by currency impacts to expenses), higher natural gas prices that are passed through to customers (approximately $152 million), an increase related to U S business operations (approximately $60 million) driven by higher rates and contracted volumes and increased gas distribution revenues (approximately $36 million), resulting from higher gas usage in the power market
- A $363 million increase at U S Franchised Electric and Gas due primarily to increased sales to retail and wholesale customers as a result of warmer weather, more efficient performance of the generation fleet, and customer growth, coupled with an increase in fuel rates primarily as a result of higher coal costs in 2005 and increased market prices for wholesale power
- A $126 million increase at International Energy due primarily to favorable foreign exchange rate changes in Brazil, and higher energy prices and volumes, and
- A $58 million increase at Crescent due primarily to higher residential developed lot sales

For a more detailed discussion of operating revenues, see the segment discussions that follow

Consolidated Operating Expenses

Year Ended December 31, 2006 as Compared to December 31, 2005 Consolidated operating expenses for 2006 decreased $923 million, compared to 2005. The change was primarily driven by:

- An approximate $5,090 million decrease due to the deconsolidation of DEFS, effective July 1, 2005
- A $239 million decrease at Crescent due primarily to the deconsolidation of Crescent, effective September 7, 2006 and softening in the residential real estate market, and

- An approximate $120 million decrease associated with the prior year recognition of unrealized losses in accumulated other comprehensive income (AOCI) as a result of the discontinuance of certain cash flow hedges entered into to hedge Field Services' commodity price risk, which were previously accounted for as cash flow hedges (see Note 8 to the Consolidated Financial Statements, "Risk Management and Hedging Activities, Credit Risk, and Financial Instruments").

Partially offsetting these decreases in expenses were:

- An approximate $3,430 million increase due to the merger with Cinergy
- A $447 million increase at Natural Gas Transmission due primarily to Canadian assets (approximately $189 million), primarily the Empress System, increased natural gas prices at Union Gas (approximately $146 million), resulting from high natural gas prices passed through to customers without a mark-up at Union Gas, higher operating and maintenance, including pipeline integrity and project development expenses (approximately $133 million), Canadian dollar foreign exchange impacts (approximately $124 million), partially offset by lower gas purchase costs at Union Gas resulting primarily from unseasonably warmer weather (approximately $157 million)
- A $341 million increase at International Energy due primarily to higher costs in Peru (approximately $109 million), driven primarily by increased ownership and resulting consolidation of Aguaytia, a reserve related to a settlement made in conjunction with the Citrus litigation (approximately $100 million), higher fuel prices and increased consumption in El Salvador (approximately $38 million), unfavorable exchange rates, increased regulatory fees and higher purchased power costs in Brazil (approximately $34 million), an increase in Mexico due to an impairment of a note receivable from Campeche (approximately $33 million), and impairments in Bolivia (approximately $28 million)
- An $179 million increase in Other due primarily to costs to achieve the Cinergy merger and the anticipated spin-off of Duke Energy's natural gas businesses (approximately $128 million and $58 million, respectively), a reserve charge related to contract settlement negotiations (approximately $65 million), partially offset by decreases due to the continued wind-down of the former DENA businesses (approximately $47 million), and
- An approximate $115 million increase at Duke Energy Carolinas driven primarily by increased fuel expenses, due primarily to higher coal costs ($188 million) and increased purchase power expense resulting primarily from less generation availability during 2006 as a result of outages at base load stations ($42 million), partially offset by lower regulatory amortization, due primarily to reduced amortization of compliance costs related to clean air legislation ($86 million), and decreased operating and maintenance expense, due primarily to a December 2005 ice storm

Year Ended December 31, 2005 as Compared to December 31, 2004 Consolidated operating expenses for 2005 decreased $3,025 million, compared to 2004 The change was primarily driven by:

- A $5,072 million decrease due to the deconsolidation of DEFS, effective July 1, 2005, and
- An approximate $100 million decrease in operating expenses at Commercial Power, mainly resulting from the sale of the Southeast Plants

Partially offsetting these decreases in expenses were:

- An approximate $675 million increase in operating expenses at Field Services driven primarily by higher average NGL and natural gas prices in the first six months of 2005
- A $640 million increase at Natural Gas Transmission due primarily to new Canadian assets (approximately $272 million), primarily gas purchase costs associated with the Empress System, increased natural gas prices at Union Gas (approximately $152 million, which is offset in revenues), foreign exchange impacts (approximately $118 million) as discussed above (offset by currency impacts to revenues), and increased gas purchases for distribution (approximately $43 million) primarily due to higher gas usage in the power market
- A $346 million increase in operating expenses at U S Franchised Electric and Gas due primarily to increased fuel expenses, driven by higher coal costs and increased generation to meet customer demand, and increased operating and maintenance expenses due primarily to increased planned outage and maintenance at generating plants, planned maintenance to improve reliability of distribution and transmission equipment, and higher storm charges in 2005, driven primarily by an ice storm in December 2005
- An approximate $120 million increase related to the recognition of unrealized losses in AOCI as a result of the discontinuance of certain cash flow hedges entered into to hedge Field Services' commodity price risk, which were previously accounted for as cash flow hedges (see Note 8 to the Consolidated Financial Statements, "Risk Management and Hedging Activities, Credit Risk, and Financial Instruments")

- An approximate $75 million charge to increase liabilities associated with mutual insurance companies in 2005
- A $74 million increase at International Energy due primarily to higher fuel prices, increased fuel volumes purchased, higher maintenance costs and the impact of foreign exchange rate changes in Brazil, offset by decreased power purchase obligations in Brazil, and
- A $64 million increase as a result of the 2004 correction of an immaterial accounting error in prior periods related to reserves at Bison.

For a more detailed discussion of operating expenses, see the segment discussions that follow

Consolidated Gains on Sales of Investments in Commercial and Multi-Family Real Estate

Consolidated gains on sales of investments in commercial and multi-family real estate were $201 million in 2006, $191 million in 2005, and $192 million in 2004 The gain in 2006 was driven primarily by pre-tax gains from the sale of two office buildings at Potomac Yard in Washington, D C and a gain on a land sale at Lake Keowee in northwestern South Carolina The gain in 2005 was driven primarily by pre-tax gains from the sales of surplus legacy land, particularly a large sale in Lancaster, South Carolina, commercial land sales, including a large sale near Washington, D C and multi-family project sales in North Carolina and Florida The gain in 2004 was driven primarily by pre-tax gains from commercial land and project sales in the Washington D C area and pre-tax gains from the sales of surplus legacy land.

Consolidated Gains (Losses) on Sales of Other Assets and Other, net

Consolidated gains (losses) on sales of other assets and other, net was a gain of $276 million for 2006, a gain of $534 million for 2005, and a loss of $416 million for 2004 The gain in 2006 was due primarily to the pre-tax gains resulting from the sale of an effective 50% interest in Crescent, creating a joint venture between Duke Energy and MSREF (approximately $250 million), and gains on settlements of customers' transportation contracts at Natural Gas Transmission (approximately $28 million), partially offset by Commercial Power's losses on sales of emission allowances (approximately $29 million). The gain in 2005 was due primarily to the pre-tax gain resulting from the DEFS disposition transaction (approximately $575 million), partially offset by net pre-tax losses at Commercial Power, principally the termination of DENA structured power contracts in the Southeast region (approximately $75 million). The loss in 2004 was due primarily to pre-tax losses on the sale of the Southeast Plants (approximately $360 million) at Commercial Power, and the termination and sale of DETM contracts ($65 million) in Other

Consolidated Operating Income

Year Ended December 31, 2006 as Compared to December 31, 2005 For 2006, consolidated operating income decreased $438 million, compared to 2005 Decreased operating income was primarily related to an approximate $575 million gain in 2005 resulting from the DEFS disposition transaction, the impacts of the deconsolidation of DEFS, effective July 1, 2005, which amounted to approximately $440 million for 2005, an approximate $190 million of cost in 2006 to achieve the Cinergy merger and the anticipated spin-off of Duke Energy's natural gas businesses, and approximately $165 million of charges in 2006 related to settlements and contract negotiations Partially offsetting these decreases were an approximately $461 million of operating income generated by legacy Cinergy in 2006 as a result of the merger, an approximate $250 million gain in 2006 on the sale of an effective 50% interest in Crescent and an approximate $250 million negative impact to operating income in 2005 related to the discontinuance of certain cash flow hedges entered into to hedge Field Services' commodity price risk

Year Ended December 31, 2005 as Compared to December 31, 2004 For 2005, consolidated operating income increased $675 million, compared to 2004 Increased operating income was due primarily to the gain in 2005 resulting from the DEFS disposition transaction and the charge in 2004 associated with the sale of the Southeast Plants in 2005, partially offset by charges in 2005 related to the discontinuance of certain cash flow hedges entered into to hedge Field Services' commodity price risk, charges in 2005 related to the termination of structured power contracts in the Southeast region and increased liabilities associated with mutual insurance companies.

Other drivers to operating income are discussed above For more detailed discussions, see the segment discussions that follow

Consolidated Other Income and Expenses

Year Ended December 31, 2006 as Compared to December 31, 2005 For 2006, consolidated other income and expenses decreased $801 million, compared to 2005. The decrease was due primarily to the $1,245 million pre-tax gains on sales of equity investments recorded in 2005, primarily associated with the sale of TEPPCO GP and Duke Energy's limited partner interest in TEPPCO LP, partially offset by an increase of approximately $253 million in equity in earnings of unconsolidated affiliates due primarily to the deconsolidation of DEFS starting July 1, 2005 and an increase of approximately $115 million of interest income resulting primarily from favorable income tax settlements in 2006

Year Ended December 31, 2005 as Compared to December 31, 2004 For 2005, consolidated other income and expenses increased $1,505 million, compared to 2004 The increase was due primarily to the $1,245 million pre-tax gains associated with the sale of TEPPCO GP and Duke Energy's limited partner interest in TEPPCO LP, equity income of $292 million for the investment in DEFS subsequent to the deconsolidation of DEFS, effective July 1, 2005, slightly offset by the realized and unrealized pre-tax losses recognized in 2005 on certain derivative contracts hedging Field Services commodity price risk which were discontinued as cash flow hedges as a result of the deconsolidation of DEFS by Duke Energy Effective with the deconsolidation of DEFS on July 1, 2005, mark-to-market changes related to the Field Services discontinued hedges are classified in Other income and expenses, net on the Consolidated Statements of Operations, while from February 22, 2005 to June 30, 2005 these mark-to-market changes were classified in Non-regulated electric, natural gas, natural gas liquids and other revenues on the Consolidated Statements of Operations

Consolidated Interest Expense

Year Ended December 31, 2006 as Compared to December 31, 2005 For 2006, consolidated interest expense increased $187 million, compared to 2005 This increase is primarily attributable to the increase in long-term debt as a result of the merger with Cinergy (an approximate $228 million impact), partially offset by reduced interest expense associated with DEFS, which was deconsolidated on July 1, 2005 (an approximate $82 million impact)

Year Ended December 31, 2005 as Compared to December 31, 2004 For 2005, consolidated interest expense decreased $216 million, compared to 2004 This decrease was due primarily to Duke Energy's debt reduction efforts in 2004 (an approximate $140 million impact) and the deconsolidation of DEFS effective July 1, 2005 (an approximate $80 million impact)

Consolidated Minority Interest Expense

Year Ended December 31, 2006 as Compared to December 31, 2005 For 2006, consolidated minority interest expense decreased $477 million, compared to 2005 This decrease primarily resulted from the 2005 gain associated with the sale of TEPPCO GP and the impact of deconsolidation of DEFS effective July 1, 2005

Year Ended December 31, 2005 as Compared to December 31, 2004 For 2005, consolidated minority interest expense increased $338 million, compared to 2004. This increase was driven primarily by increased earnings at DEFS in the first six months of 2005 as a result of the sale of TEPPCO GP and higher commodity prices, offset by the impact of the deconsolidation of DEFS effective July 1, 2005

Consolidated Income Tax Expense from Continuing Operations

Year Ended December 31, 2006 as Compared to December 31, 2005 For 2006, consolidated income tax expense from continuing operations decreased $439 million, compared to 2005 This decrease primarily resulted from lower pre-tax earnings, due primarily to the 2005 gains associated with the sale of TEPPCO GP and Duke Energy's limited partner interest in TEPPCO LP as discussed above, offset by the 2006 gain on Crescent The effective tax rate decreased in 2006 (29%) compared to 2005 (34%) The lower effective tax rate for year ended December 31, 2006 as compared to December 31, 2005 was primarily due to favorable tax settlements on research and development costs and nuclear decommissioning costs, tax benefits related to the impairment of an investment in Bolivia, and reserves and tax credits recognized on synthetic fuel operations

Year Ended December 31, 2005 as Compared to December 31, 2004 For 2005, consolidated income tax expense from continuing operations increased $775 million, compared to 2004 The increase in income tax expense from continuing operations is primarily a result of $2,058 million in higher pre-tax earnings, due primarily to the gains associated with the sale of TEPPCO GP, Duke Energy's limited partner interest in TEPPCO LP and the DEFS disposition transaction (see Note 2 to the Consolidated Financial Statements, "Acquisitions and Dispositions") Other than the increase from higher pre-tax earnings, the increase in income tax expense from continuing operations is due to an increase in the effective tax rate, which was approximately 34% in 2005, as compared to approximately 29% in 2004 The increase in the effective tax rate was due primarily to the release of approximately $52 million of income tax reserves, resulting from the resolution of various outstanding income tax issues and changes in estimates in 2004 and a $20 million tax benefit in 2004 recognized in connection with the prior year formation of Duke Energy Americas, LLC, partially offset by the $45 million taxes recorded in 2004 on the repatriation of foreign earnings that was expected to occur in 2005 associated with the American Jobs Creation Act of 2004

Consolidated (Loss) Income from Discontinued Operations, net of tax

Consolidated (loss) income from discontinued operations was ($156) million for 2006, ($701) million for 2005, and $244 million for 2004 These amounts represent results of operations and gains (losses) on dispositions related primarily to former DENA's assets and contracts outside the Midwestern and Southeastern United States, which are included in Other, and Cinergy commercial marketing and trading operations, which are included in Commercial Power, (see Note 13 to the Consolidated Financial Statements, "Discontinued Operations and Assets Held for Sale"). The 2006 amount is primarily comprised of approximately $140 million of after-tax losses associated with certain contract terminations or sales at former DENA, as a result of the 2005 decision to exit substantially all of former DENA's remaining assets and contracts outside the Midwestern United States and certain contractual positions related to the Midwestern assets, and the recognition of approximately $17 million of after-tax losses associated with exiting the Cinergy commercial marketing and trading operations

The 2005 amount is primarily comprised of an approximate $550 million non-cash, after-tax charge (approximately $900 million pre-tax) for the impairment of assets, and the discontinuance of hedge accounting and the discontinuance of the normal purchase/normal sale exception for certain positions, as a result of the decision to exit substantially all of former DENA's remaining assets and contracts outside the Midwestern United States and certain contractual positions related to the Midwestern assets. Additionally, during 2005, Duke Energy recognized after-tax losses of approximately $250 million (approximately $400 million pre-tax) as the result of selling certain gas transportation and structured contracts related to the former DENA operations. These charges were offset by the recognition of after-tax gains of approximately $125 million (approximately $200 million pre-tax) related to the recognition of deferred gains in AOCI related to discontinued cash flow hedges related to the former DENA operations

The 2004 amount is primarily comprised of a $273 million after-tax gain resulting from the sale of International Energy's Asia-Pacific Business, and an approximate $117 million after-tax gain on the sale of two partially constructed merchant power plants in the western United States offset by operating losses at the western and northeast merchant power plants

Consolidated Cumulative Effect of Change in Accounting Principle, net of tax and minority interest

During 2005, Duke Energy recorded a net-of-tax and minority interest cumulative effect adjustment for a change in accounting principle of $4 million as a reduction in earnings. The change in accounting principle related to the implementation of FIN 47, "Accounting for Conditional Asset Retirement Obligations," in which the timing or method of settlement are conditional on a future event that may or may not be within the control of Duke Energy

Segment Results

Management evaluates segment performance based on earnings before interest and taxes from continuing operations, after deducting minority interest expense related to those profits (EBIT). On a segment basis, EBIT excludes discontinued operations, represents all profits from continuing operations (both operating and non-operating) before deducting interest and taxes, and is net of the minority interest expense related to those profits. Cash, cash equivalents and short-term investments are managed centrally by Duke Energy, so the gains and losses on foreign currency remeasurement, and interest and dividend income on those balances, are excluded from the segments' EBIT. Management considers segment EBIT to be a good indicator of each segment's operating performance from its continuing operations, as it represents the results of Duke Energy's ownership interest in operations without regard to financing methods or capital structures

See Note 3 to the Consolidated Financial Statements, "Business Segments," for a discussion of Duke Energy's new segment structure

As discussed in Note 13 to the Consolidated Financial Statements, "Discontinued Operations and Assets Held for Sale" during the third quarter of 2005, the Board of Directors of Duke Energy authorized and directed management to execute the sale or disposition of substantially all former DENA's remaining assets and contracts outside the Midwestern United States and certain contractual positions related to the Midwestern assets. As a result of this exit plan, the continuing operations of the former DENA segment (which primarily include the operations of the Midwestern generation assets, former DENA's remaining Southeastern operations related to assets which were disposed of in 2004, the remaining operations of DETM, and certain general and administrative costs) have been reclassified to Commercial Power, except for DETM, which is in Other. Previously, the continuing operations of the former DENA segment were included as a component of Other in 2005 and as a component of the former DENA segment in prior periods.

Duke Energy's segment EBIT may not be comparable to a similarly titled measure of another company because other entities may not calculate EBIT in the same manner Segment EBIT is summarized in the following table, and detailed discussions follow

EBIT by Business Segment

	Years Ended December 31,				
	2006	2005	Variance 2006 vs 2005	2004	Variance 2005 vs 2004
			(in millions)		
U.S. Franchised Electric and Gas	$ 1,811	$ 1,495	$ 316	$ 1,467	$ 28
Natural Gas Transmission	1,438	1,388	50	1,329	59
Field Services[(a)]	569	1,946	(1,377)	367	1,579
Commercial Power[(b)]	21	(118)	139	(479)	361
International Energy	139	314	(175)	222	92
Crescent[(c)]	532	314	218	240	74
Total reportable segment EBIT	4,510	5,339	(829)	3,146	2,193
Other[(b)]	(581)	(518)	(63)	(207)	(311)
Total reportable segment and other EBIT	3,929	4,821	(892)	2,939	1,882
Interest expense	(1,253)	(1,066)	(187)	(1,282)	216
Interest income and other[(d)]	186	56	130	96	(40)
Consolidated earnings from continuing operations before income taxes	$ 2,862	$ 3,811	$ (949)	$ 1,753	$ 2,058

(a) In July 2005, Duke Energy completed the agreement with ConocoPhillips to reduce Duke Energy's ownership interest in DEFS from 69 7% to 50% Field Services segment data includes DEFS as a consolidated entity for periods prior to July 1, 2005 and an equity method investment for periods after June 30, 2005

(b) Amounts associated with former DENA's operations are included in Other for all periods presented, except for the Midwestern generation and Southeast operations, which are reflected in Commercial Power

(c) In September 2006, Duke Energy completed a joint venture transaction of Crescent. As a result, Crescent segment data includes Crescent as a consolidated entity for periods prior to September 7, 2006 and as an equity method investment for periods subsequent to September 7, 2006.

(d) Other includes foreign currency transaction gains and losses and additional minority interest expense not allocated to the segment results.

Minority interest expense as shown and discussed below includes only minority interest expense related to EBIT of Duke Energy's joint ventures It does not include minority interest expense related to interest and taxes of the joint ventures

The amounts discussed below include intercompany transactions that are eliminated in the Consolidated Financial Statements

U.S. Franchised Electric and Gas

	Years Ended December 31,				
	2006	2005	Variance 2006 vs. 2005	2004	Variance 2005 vs. 2004
			(in millions, except where noted)		
Operating revenues	$ 8,098	$ 5,432	$ 2,666	$ 5,069	$ 363
Operating expenses	6,319	3,959	2,360	3,613	346
Gains (losses) on sales of other assets and other, net	—	7	(7)	3	4
Operating income	1,779	1,480	299	1,459	21
Other income and expenses, net	32	15	17	8	7
EBIT	$ 1,811	$ 1,495	$ 316	$ 1,467	$ 28
Duke Energy Carolinas GWh sales[(a)]	82,652	85,277	(2,625)	82,708	2,569
Duke Energy Midwest GWh sales[(a)(b)]	46,069		46,069		

(a) Gigawatt-hours (GWh)

(b) Relates to operations of former Cinergy from the date of acquisition and thereafter

The following table shows the percentage changes in GWh sales and average number of customers for Duke Energy Carolinas The table below excludes amounts related to legacy Cinergy since results of operations of Cinergy are only included from the date of acquisition and thereafter

Increase (decrease) over prior year	**2006**	**2005**	**2004**
Residential sales	(1 2)%	3.7%	5.1%
General service sales	1 4%	1 9%	3 5%
Industrial sales	(3.8)%	1.1%	1.8%
Wholesale sales	(38 7)%	38 0%	(26 1)%
Total Duke Energy Carolinas sales[a]	(3.1)%	3.1%	(0.1)%
Average number of customers	2 0%	2 0%	1 7%

[a] Consists of all components of Duke Energy Carolinas' sales, including retail sales and wholesale sales to incorporated municipalities and to public and private utilities and power marketers

~~Year Ended December 31, 2006 as Compared to December 31, 2005~~

Operating Revenues. The increase was driven primarily by:

- A $2,651 million increase in regulated revenues due to the acquisition of Cinergy
- A $203 million increase in fuel revenues driven by increased fuel rates for retail customers due primarily to increased coal costs The delivered cost of coal in 2006 is approximately $11 per ton higher than the same period in 2005, representing an approximately 20% increase, and
- A $27 million increase related to demand from retail customers, due primarily to continued growth in the number of residential and general service customers in Duke Energy Carolinas' service territory The number of customers in 2006 increased by approximately 45,000 compared to 2005

Partially offsetting these increases were:

- A $91 million decrease in wholesale power sales. net of the impact of sharing of profits from wholesale power sales with industrial customers in North Carolina ($40 million) Sales volumes decreased by approximately 39% primarily due to production constraints caused by generation outages and pricing
- A $77 million decrease related to the sharing of anticipated merger savings by way of a rate decrement rider with regulated customers in North Carolina and South Carolina As a requirement of the merger, Duke Energy Carolinas is required to share anticipated merger savings of approximately $118 million with North Carolina customers and approximately $40 million with South Carolina customers over a one year period, and
- A $32 million decrease in GWh sales to retail customers due to unfavorable weather conditions compared to the same period in 2005 Weather statistics in 2006 for heating degree days were approximately 9% below normal as compared to 2% above normal in 2005 Overall weather statistics for both heating and cooling periods in 2006 were unfavorable compared to the same periods in 2005

Operating Expenses The increase was driven primarily by:

- A $2,245 million increase in regulated operating expenses due to the acquisition of Cinergy
- A $188 million increase in fuel expenses, due primarily to higher coal costs Fossil generation fueled by coal accounted for slightly more than 50% of total generation for year to date December 31, 2006 and 2005 and the delivered cost of coal in 2006 is approximately $11 per ton higher than the same period in 2005
- A $42 million increase in purchased power expense, due primarily to less generation availability during 2006 as a result of outages at base load stations, and
- A $24 million increase in depreciation expense, due to additional capital spending

Partially offsetting these increases were:

- An $86 million decrease in regulatory amortization, due to reduced amortization of compliance costs related to clean air legislation during 2006 as compared to the same period in 2005 Regulatory amortization expenses were approximately $225 million for the year ended December 31, 2006 as compared to approximately $311 million during the same period in 2005
- A $39 million decrease in operating and maintenance expenses, due primarily to a December 2005 ice storm, and
- A $15 million decrease in donations related to sharing of profits from wholesale power sales with charitable, educational and economic development programs in North Carolina and South Carolina For the year ended December 31, 2006, donations totaled $13 million, while for the same period in 2005, donations totaled $28 million

Other income and expenses. The increase in Other income and expenses resulted primarily from an increase in allowance for funds used during construction due mainly to the acquisition of the regulated operations of Cinergy

EBIT The increase in EBIT resulted primarily from the acquisition of the regulated operations of Cinergy, lower regulatory amortization in North Carolina, increased demand from retail customers due to continued growth in the number of residential and general service customers and decreased operating and maintenance expense in the Carolinas These changes were partially offset by lower wholesale power sales, net of sharing, rate reductions due to the merger, unfavorable weather conditions and increased purchased power expense in the Carolinas

Matters Impacting Future U.S. Franchised Electric and Gas Results

U S Franchised Electric and Gas continues to increase its customer base, maintain low costs and deliver high-quality customer service in the Carolinas and Midwest. The residential and general service sectors are expected to grow U S Franchised Electric and Gas will continue to provide strong cash flows from operations to Duke Energy Changes in weather, wholesale power market prices, service area economy, generation availability and changes to the regulatory environment would impact future financial results for U S Franchised Electric and Gas Rate reductions for merger savings will primarily cease in the second quarter of 2007 In addition, U S Franchised Electric and Gas' results will be affected by its flexibility to vary the amortization expenses associated with the North Carolina clean air legislation U S Franchised Electric and Gas amortization expense related to this clean air legislation totals $863 million from inception, with $311 million recorded in 2005 and $225 million recorded in 2006 At least $185 million of amortization will be recognized in 2007 in order to recognize the minimum cumulative amortization of approximately $1.05 billion required by the end of 2007.

Various regulatory activities will continue in 2007, including a North Carolina rate review and filings for certification for new generation and approval of various costs to be recovered in trackers. The outcomes of these matters will impact future earnings and cash flows for U S Franchised Electric and Gas As a result of additional costs and synergies that are expected from the merger with Cinergy as well as the uncertainty related to the regulatory activities mentioned above, U S Franchised Electric and Gas is unable to estimate reported segment EBIT for 2007 and beyond However, segment EBIT for 2007 is expected to be higher than in 2006 primarily due to a full-year of contributions from Cinergy's regulated operations and the expectation for more normalized weather in U S Franchised Electric and Gas' service territories

Year Ended December 31, 2005 as Compared to December 31, 2004

Operating Revenues The increase was driven primarily by:

- A $137 million increase in fuel revenues, due primarily to increased GWh sales to retail and wholesale customers and increased fuel rates for retail customers due primarily to increased coal costs Sales to retail customers increased by approximately 2%, while sales to wholesale customers increased by approximately 40% resulting in significantly more fuel revenue collections from those customers The delivered cost of coal in 2005 is approximately $7 per ton higher than in 2004
- A $109 million increase in wholesale power revenues, net of the impact of sharing of profits from wholesale power sales with industrial customers in North Carolina ($37 million), due primarily to increased sales volumes and higher market prices, approximately $42 million and $104 million, respectively Wholesale GWh sales increased by approximately 40% due to strong demand driven by favorable weather, more efficient performance by the generation fleet in 2005 and alleviation of coal constraints that limited wholesale sales opportunities in 2004 Gross margin increased by $11,000 per GWh, an 80% increase, due to higher average market rates for power resulting primarily from energy supply disruptions and record natural gas prices in 2005
- A $55 million increase in GWh sales to retail customers due to favorable weather conditions during the latter half of the year Weather statistics in 2005 for cooling degree days were approximately 7% better than normal as compared to 1% below normal in 2004, and
- A $27 million increase related to demand from retail customers, due primarily to continued growth in the number of residential and general service customers in Franchised Electric's service territory The number of customers in 2005 increased by approximately 43,000 compared to 2004

Operating Expenses The increase was driven primarily by:

- A $176 million increase in fuel expenses, due primarily to higher coal costs and increased generation to meet the strong demand of retail and wholesale customers Total generation increased by 4% compared to 2004 and generation fueled by coal accounted for more than 50 percent of total generation during both periods The delivered cost of coal in 2005 is approximately $7 per ton higher than the same period in 2004

PART II

- A $134 million increase in operating and maintenance expenses, due primarily to increased planned outage and maintenance at generating plants, planned maintenance to improve the reliability of distribution and transmission equipment and employee wages and benefits
- A $29 million increase due to higher storm charges in 2005. The increase is primarily due to a December 2005 ice storm ($46 million), which resulted in outages for approximately 700,000 customers. This is partially offset by charges for Hurricane Ivan in September 2004 ($11 million) and a wind storm in March 2004 ($7 million), and
- A $14 million increase in donations related to sharing of profits from wholesale power sales with charitable, educational and economic development programs in North Carolina and South Carolina. For the year ended December 31, 2005, donations totaled $28 million, while for the same period in 2004, donations totaled $14 million.

EBIT. The increase in EBIT resulted primarily from increased sales to wholesale customers, net of sharing, increased sales to retail customers due to favorable weather in 2005, and continued growth in the number of residential and general service customers in 2005. These changes were partially offset by increased operating and maintenance expenses, including storm costs.

Natural Gas Transmission

	Years Ended December 31,				
	2006	2005	Variance 2006 vs 2005	2004	Variance 2005 vs 2004
	(in millions, except where noted)				
Operating revenues	$ 4,523	$ 4,055	$ 468	$ 3,351	$ 704
Operating expenses	3,162	2,715	447	2,075	640
Gains (losses) on sales of other assets and other, net	47	13	34	17	(4)
Operating income	1,408	1,353	55	1,293	60
Other income and expenses, net	69	65	4	63	2
Minority interest expense	39	30	9	27	3
EBIT	$ 1,438	$ 1,388	$ 50	$ 1,329	$ 59
Proportional throughput, TBtu[a]	3,248	3,410	(162)	3,332	78

(a) Trillion British thermal units. Revenues are not significantly impacted by pipeline throughput fluctuations since revenues are primarily composed of demand charges.

Year Ended December 31, 2006 as Compared to December 31, 2005

Operating Revenues. The increase was driven primarily by:

- A $281 million increase due to Canadian assets purchased in August 2005, primarily higher processing revenues on the Empress System as a result of commodity prices
- A $157 million increase due to foreign exchange rates favorably impacting revenues from the Canadian operations as a result of the strengthening Canadian dollar (partially offset by currency impacts to expenses),
- A $146 million increase from recovery of higher natural gas commodity costs, resulting from higher natural gas prices passed through to customers without a mark-up at Union Gas. This revenue increase is offset in expenses
- A $27 million increase in U.S. business operations driven by increased processing revenues associated with transportation, and
- A $26 million increase from completed and operational pipeline expansion projects in the U.S.

Partially offsetting these increases was:

- A $186 million decrease in gas distribution revenues at Union Gas primarily resulting from lower gas usage due to warmer weather compared to 2005

Operating Expenses. The increase was driven primarily by:

- A $189 million increase in gas purchase cost associated with the Empress System
- A $146 million increase related to increased natural gas prices at Union Gas. This amount is offset in revenues
- A $133 million increase primarily related to increased operating and maintenance expenses on pipeline and storage operations, including pipeline integrity and project development expenses, higher insurance premiums, and benefit costs, and
- A $124 million increase caused by foreign exchange impacts (offset by currency impacts to revenues, as discussed above)

Partially offsetting these increases were:

- A $157 million decrease in gas purchase costs at Union Gas, primarily resulting from lower gas usage due to unseasonably warmer weather, and
- A $15 million decrease related to the resolution in 2006 of prior tax years' ad valorem tax issues

Gains (Losses) on Sales of Other Assets and Other, net. The increase was driven primarily by a $28 million gain in 2006 on the settlement of a customer's transportation contract, and a $5 million gain on the sale of Stone Mountain assets in 2006

Other Income and Expenses, net. The increase was driven primarily a pre-tax SAB No 51 gain of $15 million related to the Income Fund's issuance of additional units of the Canadian income trust fund, partially offset by a construction fee received in 2005 from an affiliate as a result of the successful completion of the Gulfstream Natural Gas System, LLC (Gulfstream), 50% owned by Duke Energy, and Natural Gas Transmission's 50% share of operating and maintenance expenses in 2006 on the Southeast Supply Header project

EBIT. The increase in EBIT is due primarily to the increase in processing earnings (primarily Empress System), the gain on settlement of a customer's transportation contract, U S business expansion, the gain on the Income Fund's issuance of additional units of the Canadian income trust fund, a gain on a property insurance settlement and the strengthening Canadian currency, partially offset by increased operating and maintenance expenses, and lower Union results primarily due to weather.

Matters Impacting Future Natural Gas Transmission Results

In June 2006, the Board of Directors of Duke Energy authorized management to pursue a plan to create two separate publicly traded companies by spinning off Duke Energy's natural gas businesses to Duke Energy shareholders This transaction was effective January 2, 2007 The new natural gas company, Spectra Energy, principally consists of Duke Energy's Natural Gas Transmission business segment and Duke Energy's 50-percent ownership interest in DEFS. The historical results of the natural gas businesses are expected to be treated as discontinued operations at Duke Energy in future periods beginning with the first quarter of 2007 As a result of the spin-off, Duke Energy's future results of operations will not include the operations of Spectra Energy.

Year Ended December 31, 2005 as Compared to December 31, 2004

Operating Revenues. The increase was driven primarily by:

- A $269 million increase due to new Canadian assets, primarily the Empress System
- A $153 million increase due to foreign exchange rates favorably impacting revenues from the Canadian operations as a result of the strengthening Canadian dollar (partially offset by currency impacts to expenses)
- A $152 million increase from recovery of higher natural gas commodity costs, resulting from higher natural gas prices that are passed through to customers without a mark-up at Union Gas This revenues increase is offset in expenses
- A $60 million increase for U S business operations driven by higher rates at Maritimes & Northeast Pipeline, LLC and Maritimes & Northeast Pipeline, LP (collectively, M & N Pipeline) and favorable commodity prices on natural gas processing activities
- A $36 million increase in gas distribution revenues, primarily due to higher gas usage in the power market, and
- A $20 million increase from completed and operational pipeline expansion projects in the U.S.

Operating Expenses. The increase was driven primarily by:

- A $272 million increase due to new Canadian assets, primarily gas purchase costs associated with the Empress System
- A $152 million increase related to increased natural gas prices at Union Gas This amount is offset in revenues
- A $118 million increase caused by foreign exchange impacts (offset by currency impacts to revenues, as discussed above)
- A $43 million increase in gas purchases for distribution, primarily due to higher gas usage in the power market, and
- A $23 million increase related to the 2004 resolution of ad valorem tax issues in various states

Other Income and Expenses, net. The increase was driven primarily by the successful completion of the Gulfstream Phase II project which went into service in February 2005 and increased volumes at Gulfstream, resulting in a $11 million increase in Gas Transmission's 50% equity earnings and a $5 million construction fee received from an affiliate. These increases were partially offset by a $16 million gain in 2004 on the sale of equity investments, primarily due to the resolution of contingencies related to prior year sales

EBIT. The increase in EBIT was due primarily to earnings from U S business expansion projects, improved U.S operations and favorable foreign exchange rate impacts from the strengthening Canadian currency, partially offset by the 2004 resolution of ad valorem tax issues.

PART II

Field Services

	Years Ended December 31,				
	2006	2005	Variance 2006 vs 2005	2004	Variance 2005 vs 2004
	(in millions, except where noted)				
Operating revenues	$ —	$ 5,530	$ (5,530)	$ 10,044	$ (4,514)
Operating expenses	5	5,215	(5,210)	9,489	(4,274)
Gains (losses) on sales of other assets and other, net	—	577	(577)	2	575
Operating income	(5)	892	(897)	557	335
Equity in earnings of unconsolidated affiliates[a]	574	292	282	—	292
Other income and expenses, net	—	1,259	(1,259)	37	1,222
Minority interest expense	—	497	(497)	227	270
EBIT	$ 569	$ 1,946	$ (1,377)	$ 367	$ 1,579
Natural gas gathered and processed/transported, TBtu/d[b]	6.8	6.8	—	6.8	—
NGL production, MBbl/d[c]	361	353	8	356	(3)
Average natural gas price per MMBtu[d]	$ 7.23	$ 8.59	$ (1.36)	$ 6.14	$ 2.45
Average NGL price per gallon[e]	$ 0.94	$ 0.85	$ 0.09	$ 0.68	$ 0.17

(a) Includes Duke Energy's 50% equity in earnings of DEFS net income subsequent to the deconsolidation of DEFS effective July 1, 2005 Results of DEFS prior to July 1, 2005 are presented on a consolidated basis

(b) Trillion British thermal units per day

(c) Thousand barrels per day

(d) Million British thermal units. Average price based on NYMEX Henry Hub

(e) Does not reflect results of commodity hedges

In July 2005, Duke Energy completed the transfer of a 19 7% interest in DEFS to ConocoPhillips, Duke Energy's co-equity owner in DEFS, which reduced Duke Energy's ownership interest in DEFS from 69 7% to 50% (the DEFS disposition transaction) and resulted in Duke Energy and ConocoPhillips becoming equal 50% owners in DEFS. As a result of the DEFS disposition transaction, Duke Energy deconsolidated its investment in DEFS and subsequently has accounted for DEFS as an investment utilizing the equity method of accounting (see Note 2 to the Consolidated Financial Statements, "Acquisitions and Dispositions")

Year Ended December 31, 2006 as Compared to December 31, 2005

Operating Revenues. The decrease was due to the DEFS disposition transaction and subsequent deconsolidation of DEFS

Operating Expenses. The decrease was due to the DEFS disposition transaction and subsequent deconsolidation of DEFS Operating expenses for 2005 were also impacted by approximately $120 million of losses recognized due to the reclassification of pre-tax unrealized losses in AOCI as a result of the discontinuance of certain cash flow hedges entered into to hedge Field Services' commodity price risk, which were previously accounted for as cash flow hedges

Gains (losses) on sales of other assets and other, net. The decrease was due primarily to an approximate pre-tax gain of $575 million on the DEFS disposition transaction in the prior year.

Equity in Earnings of Unconsolidated Affiliates. The increase is due to Duke Energy's 50% of equity in earnings of DEFS' net income for the twelve months ended December 31, 2006 as compared to equity in earnings of DEFS' net income for the six months ended December 31, 2005. DEFS' earnings during the twelve months ended December 31, 2006 have continued to be favorably impacted by increased NGL and crude oil prices as compared to the prior period, as well as increased trading and marketing gains due primarily to changes in natural gas prices and the timing of derivative and inventory transactions

Other Income and Expenses, net The decrease is due to the DEFS disposition transaction and subsequent deconsolidation of DEFS In 2005, DEFS had a pre-tax gain on the sale of its wholly-owned subsidiary, TEPPCO GP, the general partner of TEPPCO LP of $1 1 billion, and Duke Energy had a pre-tax gain on the sale of its limited partner interest in TEPPCO LP of approximately $97 million TEPPCO GP and Duke Energy's limited partner interest in TEPPCO LP were each sold to Enterprise GP Holdings LP, an unrelated third party

Minority Interest Expense. The decrease was due to the DEFS disposition transaction and subsequent deconsolidation of DEFS Minority interest expense for 2005 was due primarily to the gain on the sale of TEPPCO GP to Enterprise GP Holdings LP for approximately $1 1 billion, as discussed above.

PART II

EBIT. The decrease in EBIT from 2006 to 2005 resulted primarily from the gain on sale of TEPPCO GP and Duke Energy's limited partner interest in TEPPCO LP in 2005 and gain on the DEFS disposition transaction in 2005, which reduced Duke Energy's ownership interest in DEFS from 69 7% to 50% These decreases were partially offset by increased NGL and crude oil prices in 2006 as compared to the prior year

Matters Impacting Future Field Services Results

In June 2006, the Board of Directors of Duke Energy authorized management to pursue a plan to create two separate publicly traded companies by spinning off Duke Energy's natural gas businesses to Duke Energy shareholders This transaction was effective January 2, 2007 The new natural gas company, Spectra Energy, principally consists of Duke Energy's Natural Gas Transmission business segment, including Union Gas, and Duke Energy's 50-percent ownership interest in DEFS The historical results of the natural gas businesses are expected to be treated as discontinued operations at Duke Energy in future periods beginning with the first quarter of 2007 As a result of the spin-off, Duke Energy's future results of operations will not include the operations of Spectra Energy

Year Ended December 31, 2005 as Compared to December 31, 2004

Operating Revenues. The decrease was due to the DEFS disposition transaction and subsequent deconsolidation of DEFS This decrease was partially offset by increased revenues of ~~approximately $850 million during the six months ended June 30, 2005 versus the comparable period in the prior year which was primarily attributable to a $0.14 per gallon increase in average~~ NGL prices and a $0 66 per MMBtu increase in average natural gas prices Subsequent to June 2005, Duke Energy's 50% of equity in earnings related to its investment in DEFS are included in Equity in Earnings of Unconsolidated Affiliates

Operating Expenses The decrease was due to the DEFS disposition transaction and subsequent deconsolidation of DEFS Subsequent to June 2005, the results of DEFS are included in Equity in Earnings of Unconsolidated Affiliates This decrease was partially offset by

- Increased operating expense of approximately $675 million during the six months ended June 30, 2005 versus the comparable period in the prior year which was primarily attributable to higher average costs of raw natural gas supply, due primarily to an increase in average NGL and natural gas prices, and
- An approximate $120 million increase due to the reclassification of pre-tax unrealized losses in AOCI during the first quarter 2005 as a result of the discontinuance of certain cash flow hedges entered into to hedge Field Services' commodity price risk, which were previously accounted for as cash flow hedges (see Note 8 to the Consolidated Financial Statements, "Risk Management and Hedging Activities, Credit Risk, and Financial Instruments") After the discontinuance of these hedges, changes in their fair value are being recognized in Other results, as management considers the discontinuance to be an event which disassociates the contracts from the Field Services' results

Gains (losses) on sales of other assets and other, net The increase was primarily due to an approximate pre-tax gain of $575 million on the DEFS disposition transaction

Equity in earnings of unconsolidated affiliates The increase was driven by the equity in earnings of $292 million for Duke Energy's investment in DEFS subsequent to the completion of the DEFS disposition transaction and related deconsolidation DEFS earnings during the six months ended December 31, 2005 have continued to be favorably impacted by increased commodity prices These increases were partially offset by higher operating costs and pipeline integrity work as well as lower volumes due in part to hurricane interruptions

Other Income and Expenses, net The increase was driven primarily by an approximate $1 1 billion pre-tax gain in 2005 on the sale of DEFS' wholly-owned subsidiary, TEPPCO GP, the general partner of TEPPCO LP, and the pre-tax gain on the sale of Duke Energy's limited partner interest in TEPPCO LP of approximately $100 million TEPPCO GP and Duke Energy's limited partner interest in TEPPCO LP were each sold to Enterprise GP Holdings LP, an unrelated third party The gain was partially offset by a $33 million decrease in earnings from equity method investments, primarily as a result of the sale of TEPPCO GP and Duke Energy's limited partner interest in TEPPCO LP in the first quarter of 2005

Minority Interest Expense The increase was due primarily to the minority interest impact of the gain on the sale of TEPPCO GP to Enterprise GP Holdings LP for approximately $1 1 billion as well as increased earnings at DEFS during the six months ended June 30, 2005 due to commodity price increases This increase was partially offset by the DEFS disposition transaction and the related deconsolidation of Duke Energy's investment in DEFS effective July 1, 2005

EBIT The increase was primarily driven by the gain on sale of TEPPCO GP and Duke Energy's limited partner interest in TEPPCO LP, the gain as a result of the DEFS disposition transaction and favorable effects of commodity price increases, partially offset by the impact of Duke Energy's decreased ownership percentage resulting from the completion of the DEFS disposition transaction Also, during the first three months of 2005, Duke Energy discontinued certain cash flow hedges entered into to hedge Field Services' commodity price risk (see Note 8 to the Consolidated Financial Statements, "Risk Management and Hedging Activities, Credit Risk, and Financial Instruments") As a result of the discontinuance of these cash flow hedges and hedge accounting treatment, approximately $120 million of pre-tax unrealized losses in AOCI related to these contracts have been recognized by Field Services during the year ended December 31, 2005 Field Services' future results are subject to volatility for factors such as commodity price changes

Supplemental Data

Below is supplemental information for DEFS operating results subsequent to deconsolidation on July 1, 2005:

(in millions)	Twelve Months Ended December 31, 2006	Six Months Ended December 31, 2005
Operating revenues	$ 12,335	$ 7,463
Operating expenses	11,063	6,814
Operating income	1,272	649
Other income and expenses, net	9	1
Interest expense, net	119	62
Income tax expense	23	4
Net income	$ 1,139	$ 584

Commercial Power

	Years Ended December 31,				
	2006	2005	Variance 2006 vs 2005	2004	Variance 2005 vs 2004
	(in millions, except where noted)				
Operating revenues	$ 1,402	$ 148	$ 1,254	$ 179	$ (31)
Operating expenses	1,395	200	1,195	302	(102)
Gains (losses) on sales of other assets and other, net	(23)	(70)	47	(359)	289
Operating income	(16)	(122)	106	(482)	360
Other income and expenses, net	37	4	33	3	1
EBIT	$ 21	$ (118)	$ 139	$ (479)	$ 361
Actual plant production, GWh(a)	17,640	1,759	15,881	3,343	(1,584)
Net proportional megawatt capacity in operation	8,100	3,600	4,500	3,600	—

(a) Excludes discontinued operations

During the third quarter of 2005, the Board of Directors of Duke Energy authorized and directed management to execute the sale or disposition of substantially all of former DENA's remaining assets and contracts outside the Midwestern United States and certain contractual positions related to the Midwestern assets As a result of this exit plan, Commercial Power includes the operations of former DENA's Midwestern generation assets and remaining Southeastern operations related to the assets which were disposed of in 2004. The results of former DENA's discontinued operations, which are comprised of assets sold to LS Power, are presented in (Loss) Income From Discontinued Operations, net of tax, on the Consolidated Statements of Operations, and are discussed in consolidated Results of Operations section titled "Consolidated (Loss) Income from Discontinued Operations, net of tax "

Year Ended December 31, 2006 as compared to December 31, 2005

Operating Revenues. The increase was primarily driven by the acquisition of Cinergy non-regulated generation assets for which results, including the impacts of purchase accounting, are reflected from the date of acquisition and thereafter, but are not included in the same period in 2005 (approximately $1,240 million) Operating revenues associated with the former DENA Midwest plants were approximately $14 million higher in 2006 compared to 2005 due primarily to higher average prices and slightly higher volumes

Operating Expenses. The increase was primarily driven by the acquisition of Cinergy non-regulated generation assets for which results, including the impacts of purchase accounting, are reflected from the date of acquisition and thereafter, but are not included in the same period in 2005 (approximately $1,185 million)

Gain (losses) on Sales of Other Assets and Other, net. The increase was driven primarily by an approximate $75 million pre-tax charge in 2005 related to the termination of structured power contracts in the Southeastern Region and an approximate $6 million gain on the sale of the Pine Mountain synthetic fuel facility in 2006, partially offset by net losses of approximately $29 million on sales of emission allowances in 2006.

Other Income and Expenses, net. The increase is driven primarily by equity earnings of unconsolidated affiliates related to investments acquired in connection with the Cinergy merger in 2006.

EBIT. The increase was due primarily by the approximate $75 million pre-tax charge in 2005 related to the termination of structured power contracts in the Southeastern Region and the acquisition of Cinergy assets (approximately $69 million).

Matters Impacting Future Commercial Power Results

Commercial Power's current strategy is focused on maximizing the returns and cash flows from its current portfolio. Results for Commercial Power are sensitive to changes in power supply, power demand and fuel prices.

Segment EBIT for 2007 is expected to be higher than in 2006 primarily due to the impacts of a full year of contributions from Cinergy's Midwestern non-regulated generation portfolio, impacts of purchase accounting from the Cinergy merger, and the recovery of under-collected fuel costs in 2006. Future results for Commercial Power are subject to volatility due to the over or under-collection of fuel costs since Commercial Power is not subject to regulatory accounting pursuant to SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation." In addition, the outcome of the remand hearing by the Ohio Supreme Court in regard to the Rate Stabilization Plan (RSP) with the PUCO could affect the current tariff structure of the RSP.

Year Ended December 31, 2005 as compared to December 31, 2004

Operating Revenues. The decrease was driven primarily by the sale of the Southeast plants in 2004, including losses in 2005 associated with structured power contracts in the Southeast.

Operating Expenses. The decrease was driven primarily by the sale of the Southeast plants in 2004 and lower operating expenses in the Midwest, including:

- $61 million decrease in operations and maintenance costs, including general and administrative expenses, and depreciation expenses, and
- $38 million decrease in fuel costs.

Gains (losses) on sales of other assets and other, net. The 2005 loss was due primarily to an approximate $75 million pre-tax charge related to the termination of structured power contracts in the Southeastern Region. The 2004 results include pre-tax losses of approximately $360 million associated with the sale of the Southeast Plants.

EBIT. EBIT loss decreased driven by the loss recognized in 2004 on the sale of the Southeast Plants and decreased operating costs and lower general and administrative expense, as outlined above.

International Energy

	Years Ended December 31,				
	2006	**2005**	**Variance 2006 vs 2005**	**2004**	**Variance 2005 vs 2004**
			(in millions, except where noted)		
Operating revenues	$ 961	$ 745	$ 216	$ 619	$ 126
Operating expenses	877	536	341	462	74
Gains (losses) on sales of other assets and other, net	(1)	—	(1)	(3)	3
Operating income	83	209	(126)	154	55
Other income and expenses, net	76	117	(41)	78	39
Minority interest expense	20	12	8	10	2
EBIT	$ 139	$ 314	$ (175)	$ 222	$ 92
Sales, GWh	20,424	18,213	2,211	17,776	437
Net proportional megawatt capacity in operation[(a)]	3,996	3,937	58	4,139	(202)

(a) Excludes discontinued operations.

Year Ended December 31, 2006 as Compared to December 31, 2005

Operating Revenues. The increase was driven primarily by:

- A $118 million increase in Peru due to increased ownership and resulting consolidation of Aguaytia (See Note 2 in the Consolidated Financial Statements, "Acquisitions and Dispositions") and an increase in Egenor due to higher sales volumes, offset by lower prices
- A $40 million increase in El Salvador due to higher energy prices
- A $31 million increase in Brazil due to the strengthening of the Brazilian Real against the U.S. dollar and higher average energy prices, offset by lower volumes, and
- A $27 million increase in Argentina primarily due to higher electricity generation, prices and increased gas marketing sales

Operating Expenses. The increase was driven primarily by:

- A $109 million increase in Peru due to increased ownership and resulting consolidation of Aguaytia (See Note 2 in the Consolidated Financial Statements, "Acquisitions and Dispositions") and increased purchased power and fuel costs in Egenor
- A $100 million increase due to a reserve established as a result of a settlement made in conjunction with the Citrus litigation (see Note 17 to the Consolidated Financial Statements, "Commitments and Contingencies")
- A $38 million increase in El Salvador primarily due to higher fuel prices and increased fuel consumption
- A $34 million increase in Brazil due to the strengthening of the Brazilian Real against the U.S. dollar, increased regulatory fees, and purchased power costs
- A $33 million increase in Mexico due to an impairment of a note receivable from Campeche, and
- A $28 million increase in Bolivia due primarily to impairment charges as a result of the sale of assets in Bolivia, which was completed in February 2007

Other Income and expenses, net. The decrease was primarily driven by a $26 million decrease in NMC due to lower MTBE margins and unplanned outages and a $12 million decrease as a result of consolidation of Aguaytia in 2006 (See Note 2 in the Consolidated Financial Statements, "Acquisitions and Dispositions").

EBIT. The decrease in EBIT was primarily due to a litigation provision, impairments in Mexico and Bolivia, lower margins at NMC, higher purchased power costs in Egenor, offset by favorable hydrology and pricing in Argentina

Matters Impacting Future International Energy Results

International Energy's current strategy is focused on selectively growing its Latin American power generation business while continuing to maximize the returns and cash flow from its current portfolio. Results for International Energy are sensitive to changes in hydrology, power supply, power demand and fuel prices. Regulatory matters can also impact International Energy results, as well as impacts from fluctuations in exchange rates, most notably the Brazilian Real.

Certain of International Energy's long-term sales contracts and long-term debt in Brazil contain inflation adjustment clauses. While this is favorable to revenue in periods of inflation in the long run, as International Energy's contract prices are adjusted, there is an unfavorable impact on interest expense resulting from revaluation of International Energy's outstanding local currency debt. In periods of deflation, revenue is negatively impacted and interest expense is positively impacted.

International Energy's Argentine operations are participating in a government sponsored project to construct and operate additional gas-fired generation capacity in Argentina. International Energy's future results of operations may be impacted by the Argentine government's ability to successfully carry out this project and provide an adequate return to entities participating in the project.

Year Ended December 31, 2005 as Compared to December 31, 2004

Operating Revenues. The increase was driven primarily by:

- A $32 million increase in Brazil due to favorable exchange rates, higher average energy prices, partially offset by lower sales volumes
- A $31 million increase in El Salvador due to higher power prices and a favorable change in regulatory price bid methodology
- A $28 million increase in Argentina due primarily to higher power prices and hydroelectric generation
- A $14 million increase in Ecuador mainly due to higher volumes resulting from a lack of water for hydro competitors

- A $12 million increase in Guatemala due to higher power prices, and
- An $8 million increase in Peru due to favorable hydrological conditions and higher power prices

Operating Expenses. The increase was driven primarily by:

- A $29 million increase in El Salvador due primarily to higher fuel oil prices, increased fuel oil volumes purchased and increased transmission costs
- A $26 million increase in Ecuador due to higher maintenance, higher diesel fuel prices, increased diesel fuel volumes purchased and a prior year credit related to long term service contract termination
- A $15 million increase in Guatemala due to higher fuel prices and increased fuel volumes purchased, in addition to higher operations and maintenance costs
- A $14 million increase in Brazil due to unfavorable exchange rates and an increase in regulatory and transmission fees, partially offset by lower power purchase obligations, and
- A $14 million increase in Argentina due to higher power purchase volumes and prices

Partially offsetting these increases were;

- A $13 million decrease related to a 2004 charge for the disposition of the ownership share in Compania de Nitrogeno de Cantarell, S A de C V (Cantarell), a nitrogen production and delivery facility in the Bay of Campeche, Gulf of Mexico in 2004, and
- A $10 million decrease in general and administrative expenses primarily due to lower corporate overhead allocations and compliance costs.

Other Income and Expenses, net. The increase was driven primarily by a $55 million increase in equity earnings from the NMC investment driven by higher product margins, offset by a $20 million equity investment impairment related to Campeche in 2005

EBIT. The increase was due primarily to favorable pricing and hydrological conditions in Peru and Argentina, favorable exchange rates in Brazil and higher equity earnings from NMC, absence of a charge associated with the disposition of the ownership share in Cantarell recorded in 2004, partially offset by an equity investment impairment related to Campeche in 2005

Crescent[(a)]

	Years Ended December 31,				
	2006	2005	Variance 2006 vs 2005	2004	Variance 2005 vs 2004
			(in millions)		
Operating revenues	$ 221	$ 495	$ (274)	$ 437	$ 58
Operating expenses	160	399	(239)	393	6
Gains on sales of investments in commercial and multi-family real estate	201	191	10	192	(1)
Gains (losses) on sales of other assets and other, net	246	—	246	—	—
Operating income	508	287	221	236	51
Equity in earnings of unconsolidated affiliates	15	—	15	—	—
Other income and expenses, net	14	44	(30)	3	41
Minority interest expense	5	17	(12)	(1)	18
EBIT	$ 532	$ 314	$ 218	$ 240	$ 74

(a) In September 2006, Duke Energy completed a joint venture transaction at Crescent. As a result, Crescent segment data includes Crescent as a consolidated entity for periods prior to September 7, 2006 and as an equity investment for the periods subsequent to September 7, 2006.

Year Ended December 31, 2006 as Compared to December 31, 2005

Operating Revenues. The decrease was driven primarily by the deconsolidation of Crescent effective September 7, 2006, as well as a $272 million decrease in residential developed lot sales, primarily due to decreased sales at the LandMar division in Florida

Operating Expenses. The decrease was driven primarily the deconsolidation of Crescent effective September 7, 2006, as well as a $187 million decrease in the cost of residential developed lot sales as noted above and a $16 million impairment charge in 2005 related to a residential community in South Carolina (Oldfield)

PART II

Gains on Sales of Investments in Commercial and Multi-Family Real Estate The increase was driven primarily by an $81 million gain on the sale of two office buildings at Potomac Yard in Washington, D C along with a $52 million land sale at Lake Keowee in northwestern South Carolina in 2006, partially offset by a $41 million land sale at Catawba Ridge in South Carolina in 2005, a $15 million gain on a land sale in Charlotte, North Carolina in 2005 and a $19 million gain on a project sale in Jacksonville, Florida in 2005

Gains (Losses) on Sales of Other Assets and Other, net The increase was due to an approximate $246 million pre-tax gain resulting from the sale of an effective 50% interest in Crescent (see Note 2 in the Consolidated Financial Statements, "Acquisitions and Dispositions").

Other Income and Expenses, net The decrease is primarily due to $45 million in income related to a distribution from an interest in a portfolio of commercial office buildings in the third quarter of 2005

EBIT The increase was primarily due to the gain on sale of an ownership interest in Crescent, as noted above, as well as the sale of the Potomac Yard office buildings, partially offset by land and project sales in 2005 as discussed above

Matters Impacting Future Crescent Results

In September 2006, Duke Energy closed an agreement to create a joint venture of Crescent and sold an effective 50% interest in Crescent to the MS Members In conjunction with the formation of the Crescent JV, the joint venture, Crescent and Crescent's subsidiaries entered into a credit agreement with third party lenders under which Crescent borrowed approximately ~~$1.21 billion, net of transaction costs, of which $1.19 billion was immediately distributed to Duke Energy. Subsequent to the sale, Duke Energy deconsolidated its investment in the Crescent~~ JV and has accounted for the investment under the equity method of accounting The combination of Duke Energy's reduction in ownership and the increased interest expense at Crescent JV as a result of the debt transaction, the impacts of which will be reflected in Duke Energy's future equity earnings, will likely significantly impact the amount of equity earnings of the Crescent JV that Duke Energy will recognize in future periods. Since the Crescent JV will capitalize interest as a component of project costs, the impacts of the interest expense on Duke Energy's equity earnings will be recognized as projects are sold by the Crescent JV

Year Ended December 31, 2005 as Compared to December 31, 2004

Operating Revenues The increase was driven primarily by a $64 million increase in residential developed lot sales, due to increased sales at the Palmetto Bluff project in Bluffton, South Carolina and the LandMar affiliate in Northeastern and Central Florida.

Operating Expenses The increase was driven primarily by a $30 million increase in the cost of residential developed lot sales, due to increased developed lot sales at the projects noted above along with an $11 million increase in corporate administrative expense as a result of increased incentive compensation tied to increased operating results The increases were offset by a $16 million impairment charge in 2005 related to the Oldfield residential project near Beaufort, South Carolina as compared to $50 million in impairment and bad debt charges in 2004 related to the Twin Creeks residential project in Austin, Texas and The Rim project in Payson, Arizona

Gains on Sales of Investments in Commercial and Multi-Family Real Estate The decrease was driven primarily by:

- A $37 million decrease in real estate land sales primarily due to the $45 million gain on the sale of the Alexandria tract in the Washington, D C area in 2004, and
- A $33 million decrease in commercial project sales primarily due to the $20 million gain on the sale of a commercial project in the Washington, D C area in 2004

Partially offsetting these decreases were;

- A $37 million increase in multi-family sales primarily due to the $15 million gain on a land sale in Charlotte, North Carolina and a $19 million gain on a project sale in Jacksonville, Florida in 2005, and
- A $32 million increase in surplus land sales primarily due to a $42 million gain from a large land sale in Lancaster County, South Carolina in 2005.

Other Income and Expenses, net The increase was primarily due to $45 million in income related to a distribution from an interest in a portfolio of commercial office buildings in the third quarter of 2005.

Minority Interest Expense The increase in minority interest (benefit) expense is primarily due to increased earnings from the LandMar affiliate.

EBIT The increase was primarily due to income related to a distribution from an interest in a portfolio of commercial office buildings, a large land sale in Lancaster County, South Carolina, increased multi-family and residential developed lot sales offset by a decrease in commercial land and project sales due primarily to the sale of a commercial project and the Alexandria tract in the Washington, D C area in 2004

PART II

Supplemental Data

Below is supplemental information for Crescent operating results subsequent to deconsolidation on September 7, 2006

	September 7 through December 31, 2006
	(in millions)
Operating revenues	$ 179
Operating expenses	$ 152
Operating income	$ 27
Net income	$ 30

Other

	Years Ended December 31,				
	2006	2005	Variance 2006 vs 2005	2004	Variance 2005 vs 2004
			(in millions)		
Operating revenues	$ 142	$ 72	$ 70	$ 191	$ (119)
Operating expenses	735	556	179	388	168
Gains (losses) on sales of other assets and other, net	8	8	—	(76)	84
Operating income	(585)	(476)	(109)	(273)	(203)
Other income and expenses, net	(5)	(39)	34	41	(80)
Minority interest expense (benefit)	(9)	3	(12)	(25)	28
EBIT	$ (581)	$ (518)	$ (63)	$ (207)	$ (311)

Year Ended December 31, 2006 as Compared to December 31, 2005

Operating Revenues The increase was driven primarily by:

- An approximate $130 million increase as a result of the prior year impact of realized and unrealized mark-to-market losses on certain discontinued cash flow hedges originally entered into to hedge Field Services' commodity price risk which were accounted for as Operating Revenues prior to the deconsolidation of DEFS, effective July 1, 2005

Partially offsetting this increase was:

- A $43 million decrease due to the sale of Duke Project Services Group, Inc (DPSG) in February 2006, and
- A $21 million decrease due to a prior year mark-to-market gain related to former DENA's hedge discontinuance in the Southeast.

Operating Expenses The increase was driven primarily by:

- A $128 million increase due to costs-to-achieve in 2006 related to the Cinergy merger
- A $65 million increase due to a charge in 2006 related to contract settlement negotiations
- A $58 million increase due to costs-to-achieve in 2006 related to the spin-off of Duke Energy's natural gas businesses, and
- A $14 million increase in corporate governance and other costs due primarily to the merger with Cinergy in April 2006

Partially offsetting these increases were:

- A $47 million decrease due to the continued wind-down of the former DENA businesses, and
- A $45 million decrease due to the sale of DPSG

Other Income and Expenses, net The increase was driven primarily by an approximate $45 million favorable variance resulting from the realized and unrealized mark-to-market impacts associated with certain discontinued cash flow hedges originally entered into to hedge Field Services' commodity price risk which are recorded in Other income and expenses, net on the Consolidated Statements of Operations subsequent to the deconsolidation of DEFS, effective July 1, 2005.

EBIT The decrease was due primarily to the increase in charges in 2006 associated with Cinergy merger and natural gas business spin-off costs-to-achieve, and a charge for contract settlement negotiations These decreases were partially offset by an increase due to realized and unrealized mark-to-market impacts of certain discontinued cash flow hedges originally entered into to hedge Field Services' commodity price risk.

Matters Impacting Future Other Results

Future Other results may be subject to volatility as a result of losses insured by Bison and changes in liabilities associated with mutual insurance companies Costs associated with achieving the spin-off of the gas business and the Cinergy merger, and the wind-down of DETM could also impact future earnings for Other

Year Ended December 31, 2005 as Compared to December 31, 2004

Operating Revenues The decrease was driven primarily by:

- An approximate $130 million decrease as a result of the realized and unrealized mark-to-market impact of certain discontinued cash flow hedges originally entered into to hedge Field Services' commodity price risk (see Note 8 to the Consolidated Financial Statements, "Risk Management and Hedging Activities, Credit Risk, and Financial Instruments"), and
- An approximate $48 million decrease primarily due to the wind-downs of DETM and former DENA businesses

Partially offsetting these decreases was:

- A $21 million mark-to-market gain in 2005 related to former DENA's hedge discontinuance in the Southeast

Operating Expenses The increase was driven primarily by:

- An approximate $75 million charge to increase liabilities associated with mutual insurance companies in 2005
- A $64 million increase as a result of the 2004 correction of an immaterial accounting error in prior periods related to reserves at Bison attributable to property losses at several Duke Energy subsidiaries, and
- A $26 million increase in corporate governance costs in 2005

Partially offsetting these increases was:

- A $35 million decrease primarily associated with the continued wind-down of DETM

Gains (losses) on sales of other assets and other, net The 2004 loss was due primarily to approximately $65 million ($39 million net of minority interest expense) of pre-tax losses associated with the sale and terminations of DETM contracts

Other Income and Expenses, net The decrease was driven primarily by an approximate $64 million decrease as a result of the realized and unrealized mark-to-market impact on discontinued hedges related to Field Services' commodity price risk (See Note 8 to the Consolidated Financial Statements, "Risk Management and Hedging Activities, Credit Risk, and Financial Instruments.")

Minority Interest Expense. The change was due primarily to the continued wind-down of DETM

EBIT The decrease was due primarily to the realized and unrealized mark-to-market impact of certain discontinued cash flow hedges originally entered into to hedge Field Services' commodity price risk, the reversal of insurance reserves at Bison in 2004 and the increase in liabilities associated with mutual insurance companies in 2005

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The application of accounting policies and estimates is an important process that continues to evolve as Duke Energy's operations change and accounting guidance evolves Duke Energy has identified a number of critical accounting policies and estimates that require the use of significant estimates and judgments

Management bases its estimates and judgments on historical experience and on other various assumptions that they believe are reasonable at the time of application The estimates and judgments may change as time passes and more information about Duke Energy's environment becomes available If estimates and judgments are different than the actual amounts recorded, adjustments are made in subsequent periods to take into consideration the new information Duke Energy discusses its critical accounting policies and estimates and other significant accounting policies with senior members of management and the audit committee, as appropriate Duke Energy's critical accounting policies and estimates are discussed below

Regulatory Accounting

Duke Energy accounts for certain of its regulated operations (primarily U S Franchised Electric and Gas and Natural Gas Transmission) under the provisions of SFAS No 71, "Accounting for the Effects of Certain Types of Regulation " As a result, Duke Energy records assets and liabilities that result from the regulated ratemaking process that would not be recorded under GAAP for non-regulated entities Regulatory assets generally represent incurred costs that have been deferred because such costs are probable of future recovery in customer rates Regulatory liabilities generally represent obligations to make refunds to customers for previous collections for costs that either are not likely to or have yet to be incurred Management continually assesses whether the regulatory assets are probable of future recovery by considering factors such as applicable regulatory environment changes, recent rate orders to other regulated entities, and the status of any pending or potential deregulation legislation Based on this continual assessment, management believes the existing regulatory assets are probable of recovery This assessment reflects the current political and regulatory climate at the state, provincial and federal levels, and is subject to change in the future If future recovery of costs ceases to be probable, the asset write-offs would be required to be recognized in operating income Additionally, the regulatory agencies can provide flexibility in the manner and timing of the depreciation of property, plant and equipment, nuclear decommissioning costs and amortization of regulatory assets Total regulatory assets were $4,072 million as of December 31, 2006 and $2,319 million as of December 31, 2005 Total regulatory liabilities were $3,058 million as of December 31, 2006 and $2,338 million as of December 31, 2005 (See Note 4 to the Consolidated Financial Statements, "Regulatory Matters ")

Long-Lived Asset Impairments and Assets Held For Sale

Duke Energy evaluates the carrying value of long-lived assets, excluding goodwill, when circumstances indicate the carrying value of those assets may not be recoverable. For long-lived assets, impairment would exist when the carrying value exceeds the sum of estimates of the undiscounted cash flows expected to result from the use and eventual disposition of the asset If the asset is impaired, the asset's carrying value is adjusted to its estimated fair value When alternative courses of action to recover the carrying amount of a long-lived asset are under consideration, a probability-weighted approach is used for developing estimates of future cash flows

Duke Energy uses the best information available to estimate fair value of its long-lived assets and may use more than one source Judgment is exercised to estimate the future cash flows, the useful lives of long-lived assets and to determine management's intent to use the assets The sum of undiscounted cash flows is primarily dependent on forecasted commodity prices for sales of power or natural gas costs of fuel over periods of time consistent with the useful lives of the assets or changes in the real estate market Management's intent to use or dispose of assets is subject to re-evaluation and can change over time

A change in Duke Energy's plans regarding, or probability assessments of, holding or selling an asset could have a significant impact on the estimated future cash flows Duke Energy considers various factors when determining if impairment tests are warranted, including but not limited to:

- Significant adverse changes in legal factors or in the business climate;
- A current-period operating or cash flow loss combined with a history of operating or cash flow losses, or a projection or forecast that demonstrates continuing losses associated with the use of a long-lived asset;
- An accumulation of costs significantly in excess of the amount originally expected for the acquisition or construction of a long-lived asset;
- Significant adverse changes in the extent or manner in which an asset is used or in its physical condition or a change in business strategy;
- A significant change in the market value of an asset; and
- A current expectation that, more likely than not, an asset will be sold or otherwise disposed of before the end of its estimated useful life

Judgment is also involved in determining the timing of meeting the criteria for classification as an asset held for sale under SFAS No 144, "Accounting for the Impairment or Disposal of Long-Lived Assets " (SFAS No 144)

During 2006 and 2005, Duke Energy recorded impairments on several of its long-lived assets (For discussion of these impairments, see Note 12 to the Consolidated Financial Statements, "Impairments, Severance and Other Charges ")

Duke Energy may dispose of certain other assets in addition to the assets classified as held for sale at December 31, 2006 Accordingly, based in part on current market conditions in the merchant energy industry, it is reasonably possible that Duke Energy's current estimate of fair value of its long-lived assets being considered for sale at December 31, 2006 and its other long-lived assets, could change and that change may impact the consolidated results of operations In addition, Duke Energy could decide to dispose of additional assets in future periods, at prices that could be less than the book value of the assets

Duke Energy uses the criteria in SFAS No 144 and EITF 03-13, "Applying the Conditions in Paragraph 42 of FAS 144 in Determining Whether to Report Discontinued Operations," to determine whether components of Duke Energy that are being disposed of or are classified as held for sale are required to be reported as discontinued operations in the Consolidated Statements of Operations To qualify as a discontinued operation under SFAS No 144, the component being disposed of must have clearly distinguishable operations and cash flows Additionally, pursuant to EITF 03-13, Duke Energy must not have significant continuing involvement in the operations after the disposal (i e Duke Energy must not have the ability to influence the operating or financial policies of the disposed component) and cash flows of the assets sold must have been eliminated from Duke Energy's ongoing operations (i e Duke Energy does not expect to generate significant direct cash flows from activities involving the disposed component after the disposal transaction is completed) Assuming both preceding conditions are met, the related results of operations for the current and prior periods, including any related impairments and gains or losses on sales, are reflected as (Loss) Income From Discontinued Operations, net of tax, in the Consolidated Statements of Operations If an asset held for sale does not meet the requirements for discontinued operations classification, any impairments and gains or losses on sales are recorded in continuing operations as Gains (Losses) on Sales of Other Assets, net, in the Consolidated Statements of Operations Impairments for all other long-lived assets, other than goodwill, are recorded as Impairments and other charges in the Consolidated Statements of Operations

Impairment of Goodwill

At December 31, 2006 and 2005, Duke Energy had goodwill balances of $8,175 million and $3,775 million, respectively Duke Energy evaluates the impairment of goodwill under SFAS No 142, "Goodwill and Other Intangible Assets" (SFAS No. 142) The majority of Duke Energy's goodwill at December 31, 2006 relates to the acquisition of Cinergy in April 2006, whose assets are primarily included in the U S Franchised Electric and Gas and Commercial Power segments, and the acquisition of Westcoast Energy, Inc (Westcoast) in March 2002, whose assets are primarily included within the Natural Gas Transmission segment. The remainder relates to International Energy's Latin American operations. As of the acquisition date, Duke Energy allocates goodwill to a reporting unit, which Duke Energy defines as an operating segment or one level below an operating segment As required by SFAS No 142, Duke Energy performs an annual goodwill impairment test and updates the test if events or circumstances occur that would more likely than not reduce the fair value of a reporting unit below its carrying amount Key assumptions used in the analysis include, but are not limited to, the use of an appropriate discount rate, estimated future cash flows and estimated run rates of operation, maintenance, and general and administrative costs In estimating cash flows, Duke Energy incorporates expected growth rates, regulatory stability and ability to renew contracts as well as other factors into its revenue and expense forecasts As a result of the 2006 impairment test required by SFAS No 142, Duke Energy did not record any impairment on its goodwill.

Management continues to remain alert for any indicators that the fair value of a reporting unit could be below book value and will assess goodwill for impairment as appropriate

Revenue Recognition

Unbilled and Estimated Revenues Revenues on sales of electricity, primarily at U S Franchised Electric and Gas, are recognized when the service is provided Unbilled revenues are estimated by applying an average revenue/kilowatt hour for all customer classes to the number of estimated kilowatt hours delivered but not billed Differences between actual and estimated unbilled revenues are immaterial and are a result of customer mix

Revenues on sales of natural gas, natural gas transportation, storage and distribution as well as sales of petroleum products, primarily at Natural Gas Transmission and Field Services (prior to deconsolidation on July 1, 2005), are recognized when either the service is provided or the product is delivered Revenues related to these services provided or products delivered but not yet billed are estimated each month These estimates are generally based on contract data, regulatory information, estimated distribution usage based on historical data adjusted for heating degree days, commodity prices and preliminary throughput and allocation measurements Final bills for the current month are billed and collected in the following month. Differences between actual and estimated unbilled revenues are immaterial

Trading and Marketing Revenues The recognition of income in the Consolidated Statements of Operations for derivative activity is primarily dependent on whether the Accrual Model or MTM Model is applied While the MTM Model is the default method of accounting for all derivatives, SFAS No 133, "Accounting for Derivative Instruments and Hedging Activities," (SFAS No 133) allows for the use of the Accrual Model for derivatives designated as hedges and certain scope exceptions, including the normal purchase and normal sale exception Duke Energy designates a derivative as a hedge or a normal purchase or normal sale contract in accordance with internal hedge guidelines and the requirements provided by SFAS No 133 (For further information regarding the Accrual Model or MTM Model, see "Risk Management Accounting" below For further information regarding the presentation of gains and losses or revenue and expense in the Consolidated Statements of Operations, see Note 1 to the Consolidated Financial Statements. "Summary of Significant Accounting Policies")

Table of Contents

PART II

Risk Management Accounting

Duke Energy uses two comprehensive accounting models for its risk management activities in reporting its consolidated financial position and results of operations: the MTM Model and the Accrual Model As further discussed in Note 1 to the Consolidated Financial Statements, "Summary of Significant Accounting Policies," the MTM Model is applied to trading and undesignated non-trading derivative contracts, and the Accrual Model is applied to derivative contracts that are accounted for as cash flow hedges, fair value hedges, and normal purchases or sales, as well as to non-derivative contracts used for commodity risk management purposes For the three years ended December 31, 2006, the determination as to which model was appropriate was primarily based on accounting guidance issued by the Financial Accounting Standards Board (FASB) and the EITF

Under the MTM Model, an asset or liability is recognized at fair value on the Consolidated Balance Sheets and the change in the fair value of that asset or liability is recognized in the Consolidated Statements of Operations during the current period While former DENA was the primary business segment that used this accounting model, the U S Franchised Electric and Gas, Commercial Power and Field Services segments, as well as Other, have historically had certain transactions subject to this model For the years ended December 31, 2006, 2005 and 2004, Duke Energy applied the MTM Model to its derivative contracts, unless subject to hedge accounting or the normal purchase and normal sale exemption (as described below)

The MTM Model is applied within the context of an overall valuation framework All new and existing transactions are valued using approved valuation techniques and market data, and discounted using a risk-free based interest rate [i e - London Interbank Offered Rate (LIBOR) or US Treasury Rate] When available, quoted market prices are used to measure a contract's fair value. However, market quotations for certain energy contracts may not be available for illiquid periods or locations If no active trading market exists for a commodity or for a contract's duration, holders of these contracts must calculate fair value using internally developed valuation techniques or models Key components used in these valuation techniques include price curves, volatility, correlation, interest rates and tenor While volatility and correlation are the most subjective components, the price curve is generally the most significant component affecting the ultimate fair value for a contract subject to the MTM Model Prices for illiquid periods or locations are established by extrapolating prices for correlated products, locations or periods These relationships are routinely re-evaluated based on available market data, and changes in price relationships are reflected in price curves prospectively Consideration may also be given to the analysis of market fundamentals when developing illiquid prices A deviation in any of the components affecting fair value may significantly affect overall fair value

Valuation adjustments for performance and market risk, and administration costs are used to arrive at the fair value of the contract and the gain or loss ultimately recognized in the Consolidated Statements of Operations While Duke Energy uses common industry practices to develop its valuation techniques, changes in Duke Energy's pricing methodologies or the underlying assumptions could result in significantly different fair values and income recognition However, due to the nature and number of variables involved in estimating fair values, and the interrelationships among these variables, sensitivity analysis of the changes in any individual variable is not considered to be relevant or meaningful

Validation of a contract's calculated fair value is performed by an internal group independent of Duke Energy's deal origination areas This group performs pricing model validation, back testing and stress testing of valuation techniques, prices and other variables Validation of a contract's fair value may be done by comparison to actual market activity and negotiation of collateral requirements with third parties

For certain derivative instruments, Duke Energy applies either hedge accounting or the normal purchase and normal sales exemption in accordance with SFAS No. 133 The use of hedge accounting and the normal purchase and normal sales exemption provide effectively for the use of the Accrual Model Under this model, there is generally no recognition in the Consolidated Statements of Operations for changes in the fair value of a contract until the service is provided or the associated delivery period occurs (settlement)

Hedge accounting treatment may be used when Duke Energy contracts to buy or sell a commodity such as natural gas at a fixed price for future delivery corresponding with anticipated physical sales or purchase of natural gas (cash flow hedge) In addition, hedge accounting treatment may be used when Duke Energy holds firm commitments or asset positions and enters into transactions that "hedge" the risk that the price of a commodity, such as natural gas or electricity, may change between the contract's inception and the physical delivery date of the commodity (fair value hedge) To the extent that the fair value of the hedge instrument offsets the transaction being hedged, there is no impact to the Consolidated Statements of Operations prior to settlement of the hedge However, as not all of Duke Energy's hedges relate to the exact location being hedged, a certain degree of hedge ineffectiveness may be recognized in the Consolidated Statements of Operations

The normal purchases and normal sales exception, as provided in SFAS No 133 as amended and interpreted by Derivative Implementation Group Issue C15, "Scope Exceptions: Normal Purchases and Normal Sales Exception for Option-Type Contracts and Forward Contracts in Electricity," (DIG Issue No C15) and amended by SFAS No 149, "Amendment of Statement 133 on Derivative

Instruments and Hedging Activities," (SFAS No 149) indicates that no recognition of the contract's fair value in the Consolidated Financial Statements is required until settlement of the contract (in Duke Energy's case, the delivery of power) On a limited basis, Duke Energy applies the normal purchase and normal sales exception to certain contracts To the extent that the hedge is perfectly effective, income statement recognition for the contract will be the same under either model

In addition to derivative contracts that are accounted for as cash flow hedges, fair value hedges, and normal purchases or sales, the Accrual Model also encompasses non-derivative contracts used for commodity risk management purposes For these non-derivative contracts, there is no recognition in the Consolidated Statements of Operations until the service is provided or delivery occurs

As a result of the September 2005 decision to pursue the sale or other disposition of substantially all of former DENA's remaining assets and contracts outside the Midwestern United States, Duke Energy discontinued hedge accounting for forward natural gas and power contracts accounted for as cash flow hedges and disqualified other forward power contracts previously designated under the normal purchases normal sales exception effective September 2005

For additional information regarding risk management activities, see "Quantitative and Qualitative Disclosures about Market Risk". The "Quantitative and Qualitative Disclosures about Market Risk" include daily earnings at risk information related to commodity derivatives recorded using the MTM Model and an operating income sensitivity analysis related to hypothetical changes in certain commodity prices recorded using the Accrual Model

Pension and Other Post-Retirement Benefits

Duke Energy accounts for its defined benefit pension plans using SFAS No 87, "Employers' Accounting for Pensions," (SFAS No 87) and SFAS No 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans " Under SFAS No 87, pension income/expense is recognized on an accrual basis over employees' approximate service periods Other post-retirement benefits are accounted for using SFAS No 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions," (SFAS No 106) (See Note 22 to the Consolidated Financial Statements, "Employee Benefit Plans ")

Funding requirements for defined benefit plans are determined by government regulations, not SFAS No. 87 Duke Energy made voluntary contributions of $124 million in 2006, zero in 2005 and $250 million in 2004 to its U S plan Duke Energy anticipates making a contribution of approximately $150 million to the U S plan in 2007 Duke Energy made contributions to the Westcoast DB plans of approximately $44 million in 2006, $42 million in 2005 and $26 million in 2004 As a result of the spin-off of the natural gas businesses, Duke Energy has no future obligations to make contributions to the Westcoast DB plans Duke Energy made contributions to the Westcoast DC plans of approximately $4 million in 2006, $3 million in 2005 and $3 million in 2004 As a result of the spin-off of the natural gas businesses, Duke Energy has no future obligations to make contributions to the Westcoast DC plans

The calculation of pension expense, other post-retirement expense and Duke Energy's pension and other post-retirement liabilities require the use of assumptions Changes in these assumptions can result in different expense and reported liability amounts, and future actual experience can differ from the assumptions Duke Energy believes that the most critical assumptions for pension and other post-retirement benefits are the expected long-term rate of return on plan assets and the assumed discount rate Additionally, medical and prescription drug cost trend rate assumptions are critical for other post-retirement benefits The prescription drug trend rate assumption resulted from the effect of the Medicare Prescription Drug Improvement and Modernization Act (Modernization Act).

Duke Energy U.S Plans

Duke Energy and its subsidiaries (including legacy Cinergy businesses) maintain non-contributory defined benefit retirement plans (U S Plans). The U S Plans cover most U S employees using a cash balance formula Under a cash balance formula, a plan participant accumulates a retirement benefit consisting of pay credits that are based upon a percentage (which may vary with age and years of service) of current eligible earnings and current interest credits Certain legacy Cinergy U S employees are covered under plans that use a final average earnings formula Under a final average earnings formula, a plan participant accumulates a retirement benefit equal to a percentage of their highest 3-year average earnings, plus a percentage of their highest 3-year average earnings in excess of covered compensation per year of participation (maximum of 35 years), plus a percentage of their highest 3-year average earnings times years of participation in excess of 35 years Duke Energy also maintains non-qualified, non-contributory defined benefit retirement plans which cover certain U.S executives

Duke Energy and most of its subsidiaries also provide some health care and life insurance benefits for retired employees on a contributory and non-contributory basis Employees are eligible for these benefits if they have met age and service requirements at retirement, as defined in the plans

Duke Energy's U S Plans recognized pre-tax pension cost of $80 million, pre-tax non-qualified pension cost of $11 million and pre-tax other post-retirement benefits cost of $76 million in 2006. In 2007, Duke Energy's U S pension cost is expected to be approximately $5 million lower, non-qualified pension cost is expected to be $1 million lower and other post-retirement benefits cost is expected to be $16 million lower primarily as a result of the spin-off of the natural gas businesses

For both pension and other post-retirement plans, Duke Energy assumed that its U S plan's assets would generate a long-term rate of return of 8 5% as of September 30, 2006 The assets for Duke Energy's U S pension and other post-retirement plans are maintained by a master trust The investment objective of the master trust is to achieve reasonable returns on trust assets, subject to a prudent level of portfolio risk, for the purpose of enhancing the security of benefits for plan participants The asset allocation target was set after considering the investment objective and the risk profile with respect to the trust U S equities are held for their high expected return Non-U S equities, debt securities, and real estate are held for diversification Investments within asset classes are to be diversified to achieve broad market participation and reduce the impact of individual managers or investments Duke Energy regularly reviews its actual asset allocation and periodically rebalances its investments to its targeted allocation when considered appropriate

The expected long-term rate of return of 8 5% for the Duke Energy U S assets was developed using a weighted average calculation of expected returns based primarily on future expected returns across asset classes considering the use of active asset managers The weighted average returns expected by asset classes were 4 2% for U S equities, 1 8% for Non U S equities, 2 2% for fixed income securities, and 0 3% for real estate

If Duke Energy had used a long-term rate of 8 25% in 2006, pre-tax pension expense would have been higher by approximately $8 million and pre-tax other post-retirement expense would have been higher by approximately $1 million If Duke Energy had used a long-term rate of 8 75% pre-tax pension expense would have been lower by approximately $8 million and pre-tax other post-retirement expense would have been lower by approximately $1 million

Duke Energy discounted its future U S pension and other post-retirement obligations using a rate of 5 75% as of September 30, 2006 Duke Energy discounted its future U S pension and other post-retirement obligations using rates of 5 50% as of September 30, 2005 for its non-legacy Cinergy business pension plans and 6 00% as of April 1, 2006 for its legacy Cinergy business pension plans For legacy Cinergy plans, the discount rate reflects remeasurement as of April 1, 2006 due to the merger between Duke Energy and Cinergy Duke Energy determines the appropriate discount based on a AA bond yield curve The yield is selected based on bonds with cash flows that match the timing and amount of the expected benefit payments under the plan Lowering the discount rates by 0 25% would have decreased Duke Energy's 2006 pre-tax pension expense by approximately $2 million Increasing the discount rates by 0 25% would have increased Duke Energy's 2006 pre-tax pension expense by approximately $2 million Lowering the discount rates by 0 25% would have increased Duke Energy's 2006 pre-tax other post-retirement expense by approximately $1 million Increasing the discount rate by 0 25% would have decreased Duke Energy's 2006 pre-tax other post-retirement expense by approximately $1 million

Duke Energy's U S post-retirement plan uses a medical care trend rate which reflects the near and long-term expectation of increases in medical health care costs Duke Energy's U S post-retirement plan uses a prescription drug trend rate which reflects the near and long-term expectation of increases in prescription drug health care costs As of September 30, 2006, the medical care trend rates were 8 50%, which grades to 4 75% by 2013 As of September 30, 2006, the prescription drug trend rate was 13 00%, which grades to 4 75% by 2022 If Duke Energy had used health care trend rates one percentage point higher, pre-tax other post-retirement expense would have been higher by $6 million If Duke Energy had used health care trend rates one percentage point lower, pre-tax other post-retirement expense would have been lower by $5 million

Future changes in plan asset returns, assumed discount rates and various other factors related to the participants in Duke Energy's pension and post-retirement plans will impact Duke Energy's future pension expense and liabilities Management cannot predict with certainty what these factors will be in the future

Westcoast Plans

Westcoast and its subsidiaries maintain contributory and non-contributory defined benefit (DB) and defined contribution (DC) retirement plans covering substantially all employees The DB plans provide retirement benefits based on each plan participant's years of service and final average earnings Under the DC plans, company contributions are determined according to the terms of the plan and based on each plan participant's age, years of service and current eligible earnings Westcoast also provides health care and life insurance benefits for retired employees on a non-contributory basis Employees are eligible for these benefits if they have met age and service requirements at retirement, as defined in the plans Effective December 31, 2003, a new plan was implemented for all non bargaining employees and the majority of bargaining employees The new plan applied to employees retiring on and after January 1, 2006 The new plan is predominantly a defined contribution plan as compared to the existing defined benefit program

PART II

Westcoast recognized pre-tax pension cost of $22 million, pre-tax non-qualified pension cost of $6 million and pre-tax other post-retirement benefits cost of $12 million in 2006 In 2007, As a result of the spin-off of the natural gas businesses, Duke Energy will not incur any future pension costs associated with the Westcoast plan

The expected long-term rate of return for the Westcoast plans assets was 7 25% as of September 30, 2006 The Westcoast plans assets for registered pension plans are maintained by a master trust The investment objective of the master trust is to achieve reasonable returns on trust assets, subject to a prudent level of portfolio risk, for the purpose of enhancing the security of benefits for plan participants The asset allocation target was set after considering the investment objective and the risk profile with respect to the trust Canadian equities are held for their high expected return Non-Canadian equities are held for their high expected return as well as diversification relative to Canadian equities and debt securities Debt securities are also held for diversification

The expected long-term rate of return of 7 25% and 7 50% as of September 30, 2006 and 2005, respectively, for the Westcoast assets was developed using a weighted average calculation of expected returns based primarily on future expected returns across asset classes considering the use of active asset managers The weighted average returns expected by asset classes were 2 5% for Canadian equities, 1 3% for U S equities, 1 4% for Europe, Australasia and Far East equities, and 2 0% for fixed income securities For 2006, the expected long-term rate of return used to calculate pension expense was 7 5% Lowering the expected rate of return on assets by 0 25% (from 7 50% to 7 25%) would have increased Westcoast's 2006 pre-tax pension expense by approximately $1 million Increasing the expected rate of return by 0 25% (from 7 50% to 7 75%) would have decreased Westcoast's 2006 pre-tax pension expense by approximately $1 million The Westcoast other post-retirement plan does not hold any assets

Westcoast discounted its future pension and other post-retirement obligations using a rate of 5 00% as of September 30, 2006 and 2005. For Westcoast, the discount rate used to determine the pension and other post-retirement obligations is prescribed as the yield on Canadian corporate AA bonds at the measurement date of September 30 The yield is selected based on bonds with cash flows that match the timing and amount of the expected benefit payments under the plan For 2006, the discount rate used to calculate pension expense was 5 00% Lowering the discount rate by 0 25% (from 5 00% to 4 75%) would have increased Duke Energy's 2006 pre-tax pension expense by approximately $2 million Increasing the discount rate by 0 25% (from 5 00% to 5 25%) would have decreased Duke Energy's 2006 pre-tax pension expense by approximately $2 million Lowering the discount rate by 0 25% (from 5 00% to 4 75%) would have increased Duke Energy's 2006 pre-tax other post-retirement expense by approximately $1 million Increasing the discount rate by 0 25% (from 5 00% to 5 25%) would have decreased Duke Energy's 2006 pre-tax other post-retirement expense by approximately $1 million

The Westcoast post-retirement plans use a medical care trend rate which reflects the near and long-term expectation of increases in medical costs As of September 30, 2006, the health care trend rates were 8 00%, which grades to 5 00% by 2009 If Westcoast had used a health care trend rate one percentage point higher, pre-tax other post-retirement expense would have been higher by $2 million If Westcoast had used a health care trend rate one percentage point lower, pre-tax other post-retirement expense would have been lower by less than $1 million

LIQUIDITY AND CAPITAL RESOURCES

Known Trends and Uncertainties

Duke Energy will rely primarily upon cash flows from operations, as well as its cash, cash equivalents and short-term investments to fund its liquidity and capital requirements for 2007 The current cash, cash equivalents and short-term investments and future cash generated from operations may be used by Duke Energy to continue with its February 2005 announced plan to periodically repurchase up to an aggregate of $2 5 billion of common stock over a three year period In June 2006, the share repurchase plan was suspended At the time of the suspension of the repurchase plan, Duke Energy had repurchased approximately 50 million shares of common stock for approximately $1 4 billion since inception of the repurchase plan In October 2006, Duke Energy's Board of Directors authorized the reactivation of the share repurchase plan for Duke Energy of up to $500 million of share repurchases after the spin-off of the natural gas businesses In addition, Duke Energy's future cash flows will be negatively impacted by the spin-off of the natural gas businesses effective January 2, 2007 For the year ended December 31, 2006, operating, investing and financing cash flows provided/(used) by the natural gas businesses, including distributions from Duke Energy's 50% investment in DEFS, were approximately $1 7 billion, $(0 6) billion and $(0 2) billion, respectively

A material adverse change in operations or available financing may impact Duke Energy's ability to fund its current liquidity and capital resource requirements

Duke Energy currently anticipates net cash provided by operating activities in 2007 to be lower than in 2006, primarily as a result of the following:

- Lower operating cash flows as a result of the spin-off of the natural gas businesses, as discussed above; and,

- Lower operating cash flows due to the sale of an effective 50% interest in the Crescent JV in September 2006

These lower operating cash flows are expected to be partially offset by the following:

- Lower costs incurred related to the merger with Cinergy; and,
- Higher operating results of legacy Cinergy businesses as a result of ownership for the entire year 2007

Additionally, Duke Energy anticipates funding its defined benefit pension plans with approximately $150 million of cash during 2007, as compared to $172 million during 2006.

Ultimate cash flows from operations are subject to a number of factors, including, but not limited to, regulatory constraints, economic trends, and market volatility (see Item 1A "Risk Factors" for details).

Duke Energy projects 2007 capital and investment expenditures of approximately $3 3 billion, primarily consisting of approximately:

- $2 8 billion at U S Franchised Electric and Gas, including $0 4 billion of North Carolina Clean Air Expenditures
- $0 3 billion at Commercial Power
- $0 2 billion combined at International Energy and Other

Duke Energy continues to focus on reducing risk and restructuring its business for future success and will invest principally in its strongest business sectors with an overall focus on positive net cash generation. Based on this goal, approximately 85 percent of total projected 2007 capital expenditures are allocated to the U.S. Franchised Electric and Gas segment. Total U.S Franchised Electric and Gas projected 2007 capital and investment expenditures include approximately $1 5 billion for maintenance and upgrades of existing plants and infrastructure to serve load growth, approximately $0 7 billion of environmental expenditures, and approximately $0 6 billion of expansion capital Duke Energy's U S Franchised Electric and Gas business segment is evaluating the construction of several large, new electric generating plants in North Carolina, South Carolina, and Indiana During this evaluation process, Duke Energy has begun to see significant increases in the estimated costs of these projects driven by strong domestic and international demand for the material, equipment, and labor necessary to construct these facilities In October 2006, Duke Energy made a filing with the NCUC related to the Duke Energy Carolinas' request for a CPCN for the Cliffside project In this filing, Duke Energy stated that due to the rising costs described above, the cost of building the Cliffside units could be approximately $3 billion, excluding AFUDC The costs described above are expected to continue to increase causing the overall cost of the Cliffside project to increase, until such time as the NCUC issues a CPCN and Duke Energy is able to enter into definitive agreements with necessary material and service providers On February 28, 2007, the NCUC issued a notice of decision approving the construction of one unit at the Cliffside Steam Station The NCUC stated that it will issue a full order in the near future Duke Energy will review the NCUC's order, once issued, and determine whether to proceed with the Cliffside Project or consider other alternatives, including additional gas fired generation. Duke Energy is attempting to obtain approval for the upfront recovery of development costs related to a proposed nuclear power plant Duke Energy does not anticipate beginning construction of the proposed nuclear power plant without adequate assurance of cost recovery from the state regulators In November 2006, Duke Energy received approval for nearly $260 million of future federal tax credits related to costs to be incurred for the modernization of the Cliffside facility as well as the Integrated Gasification on Combined Cycle (IGCC) plant in Indiana

Duke Energy Indiana's estimated costs associated with the potential construction of an IGCC plant in Indiana have also increased Duke Energy Indiana's publicly filed testimony with the Indiana Utility Regulatory Commission indicates that industry (EPRI) total capital requirement estimates for a facility of this type and size are now in the range of $1 6 billion to $2 1 billion (including escalation to 2011 and owner's specific site costs).

Duke Energy anticipates its debt to total capitalization ratio to be approximately 38% by the end of 2007, as compared to 43% at the end of 2006 This reduction is primarily due to the impacts of the spin-off the natural gas businesses in 2007 Duke Energy does not expect its total debt balance (including outstanding commercial paper balances) to change significantly in 2007, excluding the impacts of approximately $8 6 billion of debt transferred to Spectra Energy as a result of the spin-off of the natural gas businesses

Excluding the debt which was transferred in connection with the spin-off of the natural gas businesses on January 2, 2007, Duke Energy has expected debt maturities of approximately $1 1 billion in 2007 Duke Energy expects to refinance approximately $0 5 billion of these maturities Based upon anticipated 2007 cash flows from operations and capital expenditure and dividend payment plans, Duke Energy expects to increase outstanding commercial paper balances by approximately $0 6 billion during 2007 Current total available capacity under Duke Energy's commercial paper facilities is sufficient to meet these additional requirements

Duke Energy monitors compliance with all debt covenants and restrictions, and does not currently believe that it will be in violation or breach of its debt covenants. However, circumstances could arise that may alter that view If and when management had a belief that such potential breach could exist, appropriate action would be taken to mitigate any such issue Duke Energy also maintains an active dialogue with the credit rating agencies, and believes that the current credit ratings are positioned for potential improvement evidenced by positive outlooks at Duke Energy and most of its subsidiaries

Operating Cash Flows

Net cash provided by operating activities was $3,748 million in 2006 compared to $2,818 million in 2005, an increase of $930 million The increase in cash provided by operating activities was due primarily to the following:

- The impacts of the merger with Cinergy, effective April 3, 2006,
- Collateral received by Duke Energy (approximately $540 million) in 2006 from Barclays, partially offset by
- The settlement of the payable to Barclays (approximately $600 million) in 2006, and
- An approximate $400 million decrease in 2006 due to the net settlement of the remaining DENA contracts

Net cash provided by operating activities was $2,818 million in 2005 compared to $4,168 million in 2004, a decrease of $1,350 million The decrease in cash provided by operating activities was due primarily to the following:

- Approximately $750 million of additional net cash collateral posted by Duke Energy during 2005 attributable to increased crude oil prices, as well as increases to the forward market prices of power,
- An approximate $900 million increase in taxes paid, net of refunds, in 2005, and,
- The impacts of the deconsolidation of DEFS effective July 1, 2005

These decreases were offset by an increase in cash provided due to an approximate $234 million decrease in contributions to company-sponsored pension plans in 2005

Investing Cash Flows

Net cash used in investing activities was $1,328 million in 2006 compared to $126 million in 2005, an increase in cash used of $1,202 million Net cash used in investing activities was $126 million in 2005 compared to $793 million in 2004, a decrease in cash used of $667 million

The primary use of cash related to investing activities is capital and investment expenditures, detailed by business segment in the following table

Capital and Investment Expenditures by Business Segment

	Years Ended December 31,		
	2006	2005	2004
		(in millions)	
U.S. Franchised Electric and Gas[a]	$ 2,381	$ 1,350	$ 1,126
Natural Gas Transmission	790	930	544
Field Services[b]	—	86	202
Commercial Power	209	2	7
International Energy	58	23	28
Crescent[c][d]	507	599	568
Other	131	29	54
Total consolidated	$ 4,076	$ 3,019	$ 2,529

(a) Amounts include capital expenditures associated with North Carolina clean-air legislation of $403 million in 2006, $310 million in 2005 and $106 million in 2004 which are included in Capital Expenditures within Cash Flows from Investing Activities on the accompanying Consolidated Statements of Cash Flows

(b) As a result of the deconsolidation of DEFS, effective July 1, 2005, Field Services amounts for 2005 only include DEFS capital and investment expenditures for periods prior to July 1, 2005

(c) Amounts include capital expenditures associated with residential real estate of $322 million for the period from January 1, 2006 through the date of deconsolidation (September 7, 2006), $355 million in 2005, and $322 million in 2004 which are included in Capital Expenditures for Residential Real Estate within Cash Flows from Operating Activities on the accompanying Consolidated Statements of Cash Flows

(d) As a result of the deconsolidation of Crescent, effective September 7, 2006, Crescent amounts for 2006 only include Crescent capital and investment expenditures for periods prior to September 7, 2006

The increase in cash used in investing activities in 2006 as compared to 2005 is primarily due to the following:

- Increased capital and investment expenditures of $1,090 million, excluding Crescent's residential real estate investment, primarily as a result of capital expenditures at U S Franchised Electric and Gas, primarily due to the acquisition of Cinergy in April 2006, the acquisition of the Rockingham facility in 2006 and increased expenditures associated with North Carolina clean-air legislation; and,

- Increased purchases of short-term investments of approximately $900 million in 2006 as compared to 2005, due primarily to the proceeds from the Crescent debt financing.

These increases were partially offset by the following:

- An increase in proceeds received from asset sales in 2006 as compared to 2005 Asset sales activity in 2006 of approximately $2.9 billion primarily involved the disposal of the former DENA operations outside of the Midwestern United States, Cinergy's commercial marketing and trading business operations, as well as the Crescent JV transaction. Asset sales activity in 2005 of approximately $2 4 billion primarily involved the disposition of the investments in TEPPCO as well as the DEFS disposition transaction.

The decrease in cash used in investing activities in 2005 as compared to 2004 is primarily due to the following:

- An increase in proceeds from the sale of assets in 2005 as compared to 2004 Asset sales activity in 2005 of approximately $2 4 billion primarily involved the disposition of the investments in TEPPCO as well as the DEFS disposition transaction Asset sales activity in 2004 of approximately $1 6 billion primarily involved the sales of the Asia-Pacific Business, Southeast Plants and Moapa and Luna partially completed facilities; and,
- Decreased amounts of cash invested in short-term investments in 2005 as compared to 2004.

These decreases were partially offset by the following:

- Increased capital and investment expenditures, excluding Crescent's residential real estate investments, of $460 million primarily as a result of the approximate $230 million acquisition of the Empress System at Natural Gas Transmission and an increase in expenditures associated with North Carolina clean-air legislation.

Financing Cash Flows and Liquidity

Duke Energy's consolidated capital structure as of December 31, 2006, including short-term debt, was 43% debt, 55% common equity and 2% minority interests The fixed charges coverage ratio, calculated using SEC guidelines, was 3 2 times for 2006, which includes a pre-tax gain of approximately $250 million on the sale of an effective 50% interest in Crescent, 4 7 times for 2005, which includes a pre-tax gain on the sale of TEPPCO GP and LP of approximately $0 9 billion, net of minority interest, and 2 3 times for 2004.

Net cash used in financing activities was $1,961 million in 2006 compared to $2,717 million in 2005, a decrease of $756 million The change was due primarily to the following:

- An approximate $1 1 billion increase in proceeds from the issuance of long-term debt in 2006, net of redemptions, due primarily to the approximate $1 2 billion of debt proceeds from the Crescent JV transaction, and
- An approximate $400 million decrease in share repurchases under Duke Energy's share repurchase plan.

These increases were partially offset by

- An approximate $400 million increase in dividends paid due to the increase in the quarterly dividend paid per share combined with a larger number of shares outstanding, primarily attributable to the 313 million shares issued in connection with the Cinergy merger, and
- The repayment of approximately $400 million of notes payable and commercial paper in 2006 due primarily to proceeds received from asset sales

Net cash used in financing activities was $2,717 million in 2005 compared to $3,278 million in 2004, a decrease of $561 million The change was due primarily to the following:

- Approximately $3 0 billion of lower redemptions, net of paydowns, of long-term debt, commercial paper, notes payable, preferred and preference stock, and preferred stock of a subsidiary during 2005 as compared to 2004 as a result of an effort to reduce debt balances in 2004

This decrease was partially offset by:

- Approximately $2 6 billion of lower proceeds from common stock transactions during 2005, primarily driven by the settlement of the forward purchase contract component of Duke Energy's Equity Units in May and November 2004 for total proceeds of $1 7 billion and the repurchase of 32 6 million shares of common stock for $933 million in 2005.

With cash, cash equivalents and short-term investments on hand at December 31, 2006 of approximately $2 5 billion and a more stable portfolio of businesses, Duke Energy has financial flexibility to buy back common stock, invest incrementally or pay down additional debt Duke Energy is evaluating these options and will determine the best economic decision to meet the needs of shareholders and the long-term financial strength of Duke Energy

Significant Financing Activities—Year Ended 2006. During the year ended December 31, 2006, Duke Energy's consolidated credit capacity increased by approximately $842 million, primarily due to the merger with Cinergy This increase was net of other reductions in credit capacity due to the terminations of an $800 million syndicated credit facility and $590 million of other bi-lateral credit facilities The terminations of these credit facilities primarily reflect Duke Energy's reduced liquidity needs as a result of exiting the former DENA business.

During the year ended December 31, 2006, Duke Energy increased the portion of outstanding commercial paper and pollution control bond balances classified as long-term from $472 million to $929 million. This non-current classification is due to the existence of long-term credit facilities which back-stop these balances along with Duke Energy's intent to refinance such balances on a long-term basis.

During 2006, Duke Energy has repurchased approximately 17 5 million shares of its common stock for approximately $500 million

In November 2006, Union Gas issued 4 85% fixed-rate debenture bonds denominated in 125 million Canadian dollars (approximately $108 million U.S dollar equivalents as of the closing date) due in 2022

In October 2006, Duke Energy Carolinas issued $150 million in tax-exempt floating-rate bonds The bonds are structured as variable-rate demand bonds, subject to weekly remarketing and bear a final maturity of 2031. The initial interest rate was set at 3 72% The bonds are supported by an irrevocable 3-year direct-pay letter of credit and were issued through the North Carolina Capital Facilities Finance Agency to fund a portion of the environmental capital expenditures at the Marshall and Belews Creek Steam Stations

During October 2006, the $130 million bi-lateral credit facility at Spectra Energy Capital was cancelled. In addition, the remaining $120 million bi-lateral credit facility was cancelled in ~~November 2006 and reissued at Duke Energy for the same amount with the same terms and conditions.~~

In September 2006, prior to the completion of the partial sale of Crescent to the MS Members as discussed in Note 2 to the Consolidated Financial Statements, "Acquisitions and Dispositions," Crescent issued approximately $1 23 billion principal amount of debt The net proceeds from the debt issuance of approximately $1 21 billion were recorded as a Financing Activity on the Consolidated Statements of Cash Flows As a result of Duke Energy's deconsolidation of Crescent effective September 7, 2006, Crescent's outstanding debt balance of $1,298 million was removed from Duke Energy's Consolidated Balance Sheets

In September 2006, Union Gas entered into a fixed-rate financing agreement denominated in 165 million Canadian dollars (approximately $148 million in U S. dollar equivalents as of the issuance date) due in 2036 with an interest rate of 5 46%

In September 2006, the Income Fund sold approximately 9 million previously unissued Trust Units at a price of 12 15 Canadian dollars per Trust Unit for total proceeds of 104 million Canadian dollars, net of commissions and expenses of other expenses of issuance The sale of approximately 9 million Trust Units reduced Duke Energy's ownership interest in the Income Fund to approximately 46% at December 31, 2006 As a result of the sale of additional Trust Units, Duke Energy recognized an approximate $15 million U S Dollar pre-tax SAB No. 51 gain on the sale of subsidiary stock The proceeds from the offering plus the draw down of approximately 39 million Canadian dollars on an available credit facility were used by the Income Fund to acquire a 100% interest in Westcoast Gas Services, Inc Subsequent to this transaction, Duke Energy had an approximate 46% ownership interest in the Income Fund.

In August 2006, Duke Energy Kentucky issued approximately $77 million principal amount of floating rate tax-exempt notes due August 1, 2027 Proceeds from the issuance were used to refund a like amount of debt on September 1, 2006 then outstanding at Duke Energy Ohio Approximately $27 million of the floating rate debt was swapped to a fixed rate concurrent with closing

In June 2006, Duke Energy Indiana issued $325 million principal amount of 6 05% senior unsecured notes due June 15, 2016 Proceeds from the issuance were used to repay $325 million of 6 65% First Mortgage Bonds that matured on June 15, 2006

During the second, third and fourth quarters of 2006, Duke Energy's $742 million of convertible debt became convertible into approximately 31.7 million shares of Duke Energy common stock due to the market price of Duke Energy common stock achieving a specified threshold during each respective quarter Holders of the convertible debt were able to exercise their right to convert on or prior to each quarter end During the second and third quarters, approximately $632 million of debt was converted into approximately 26 7 million shares of Duke Energy Common Stock. At December 31, 2006, the balance of the convertible debt is approximately $110 million.

Significant Financing Activities—Year Ended 2005. In connection with the up to $2 5 billion share repurchase program announced in February 2005, Duke Energy entered into an accelerated share repurchase transaction Duke Energy repurchased and retired 30 million shares of its common stock from an investment bank at the March 18, 2005 closing price of $27 46 per share (total of approximately $834 million, including approximately $10 million in commissions and other fees) The final settlement with the investment bank occurred on September 22, 2005 for approximately $25 million in cash The final settlement price was the difference between the initial settlement price of $27 46 per share and the volume weighted average price per share of actual shares purchased by the investment bank of $28 42 per share Duke Energy also entered into a separate open-market purchase plan with the investment bank on March 18, 2005 to repurchase up to an additional 20 million shares of its common stock through December 27, 2005 As of May 9, 2005 (the date Duke and Cinergy announced a merger agreement), Duke Energy had already repurchased 2 6 million shares of its common stock through the separate open-market purchase plan at a weighted average price of $28 97 per share In May 2005, in connection with the anticipated merger with Cinergy, Duke Energy suspended additional repurchases under the open market purchase plan For the year ended December 31, 2005 a total of 32 6 million shares of common stock were repurchased under both share repurchase programs for approximately $933 million

In December 2005, the Income Fund, a Canadian income trust fund, was created which sold approximately 40% ownership in the Canadian Midstream operations for proceeds, net of underwriting discount, of approximately $110 million In January 2006, a subsequent greenshoe sale of additional ownership interests, pursuant to an overallotment option, in the Income Fund were sold for approximately $10 million

In November 2005, International Energy issued floating rate debt in Guatemala for $87 million (in USD) and in El Salvador for $75 million (in USD) These debt issuances have variable interest rate terms and mature in 2015

On September 21, 2005, Union Gas entered into a fixed-rate financing agreement denominated in 200 million Canadian dollars (approximately $171 million in U S dollar equivalents as of the issuance date) due in 2016 with an interest rate of 4 64%

In August 2005, DEI issued project-level debt in Peru, of which $75 million is denominated in U S dollars and approximately $34 million (in U S dollar equivalents as of the issuance date) is denominated in Peru Nuevos Soles This debt has terms ranging from four to six years as well as variable or fixed interest rate terms, as applicable

On March 1, 2005, redemption notices were sent to the bondholders of the $100 million PanEnergy 8 625% bonds due in 2025 These bonds were redeemed on April 15, 2005 at a redemption price of 104 03 or approximately $104 million

During the first quarter of 2005, Duke Energy increased the portion of outstanding commercial paper balances classified as long-term debt from $150 million to $300 million This non-current classification is due to the existence of long-term credit facilities which back-stop these commercial paper balances along with Duke Energy's intent to refinance such balances on a long-term basis

In December 2004, Duke Energy reached an agreement to sell its partially completed Gray's Harbor power generation facility (Grays Harbor) to an affiliate of Invenergy LLC In 2004, Duke Energy terminated its capital lease with the dedicated pipeline which would have transported natural gas to Grays Harbor As a result of this termination, approximately $94 million was paid by Duke Energy in January 2005

Preferred and Preference Stock of Duke Energy. In December 2005, Duke Energy redeemed all Preferred and Preference stock without Sinking Fund Requirements for approximately $137 million and recognized an immaterial loss on the redemption

Available Credit Facilities and Restrictive Debt Covenants. Duke Energy's credit agreements contain various financial and other covenants Failure to meet those covenants beyond applicable grace periods could result in accelerated due dates and/or termination of the agreements As of December 31, 2006, Duke Energy was in compliance with those covenants In addition, some credit agreements may allow for acceleration of payments or termination of the agreements due to nonpayment, or to the acceleration of other significant indebtedness of the borrower or some of its subsidiaries None of the debt or credit agreements contain material adverse change clauses

(For information on Duke Energy's credit facilities as of December 31, 2006, see Note 15 to the Consolidated Financial Statements, "Debt and Credit Facilities ")

Credit Ratings. Duke Energy and certain subsidiaries each hold credit ratings by Standard & Poor's (S&P) and Moody's Investors Service (Moody's) In addition, certain subsidiaries transferred to Spectra Energy hold credit ratings by DBRS (formerly Dominion Bond Rating Service) Actions taken by ratings agencies subsequent to January 2, 2007 related to businesses transferred to Spectra Energy are not reflected herein since such actions have no impact on the ongoing operations of Duke Energy post spin-off

In May 2006, S&P changed the outlook of Duke Energy and all of its subsidiaries (with the exception of Maritimes & Northeast Pipeline, LLC and Maritimes & Northeast Pipeline, LP (collectively M&N Pipeline) and DETM from stable to positive reflecting Duke Energy's announcement to sell Cinergy's commercial trading and marketing operations

In April 2006, following the completion of Duke Energy's merger with Cinergy, S&P removed Cinergy and its subsidiaries from credit-watch negative where they had been placed in May 2005 following the Cinergy merger announcement S&P lowered Cinergy's Corporate Credit Rating (CCR) consistent with Duke Energy's CCR as disclosed in the table below As a result of Cinergy's lower CCR, S&P lowered the senior unsecured credit rating of Cinergy Corp reflecting the structural subordination of its debt In addition, S&P reassessed its view of the structural subordination for the debt outstanding at Spectra Energy Capital, Duke Energy Ohio, Duke Energy Indiana, and Duke Energy Kentucky and assigned the senior unsecured credit ratings at these entities equal to Duke Energy's CCR This resulted in the senior unsecured credit rating of Spectra Energy Capital being raised one ratings level to BBB and no changes to the senior unsecured ratings of Duke Energy Ohio, Duke Energy Indiana, and Duke Energy Kentucky as disclosed in the table below At the same time, S&P assigned a senior unsecured credit rating to Duke Energy Carolinas equal to Duke Energy's CCR and left the credit ratings of the Spectra Energy Capital subsidiaries (Texas Eastern Transmission, LP, Westcoast, Union Gas and M&N Pipeline) and DETM unchanged At the completion of S&P's April action, all the credit ratings were on stable outlook S&P last affirmed its credit ratings for M&N Pipeline in July 2006 where they have remained unchanged with a stable outlook for the last several years

In April 2006, upon Duke Energy's completion of the merger with Cinergy, Moody's upgraded the credit ratings of Duke Energy Carolinas (formerly rated as Duke Energy by Moody's prior to the merger), Spectra Energy Capital and Texas Eastern Transmission, LP one ratings level each and assigned an issuer rating to New Duke Energy The credit ratings resulting from the April action are as disclosed in the table below, except for businesses transferred to Spectra Energy entities as discussed above The credit ratings of Spectra Energy Capital and Texas Eastern Transmission, LP were Baa2 and Baa1 respectively following Moody's April action. Moody's concluded their April action placing New Duke Energy and Duke Energy Carolinas on positive outlook and Spectra Energy Capital and Texas Eastern Transmission, LP on stable outlook Moody's also confirmed all of Cinergy and its subsidiaries credit ratings and changed the outlook to positive with the exception of Duke Energy Indiana, which was left on stable outlook Moody's noted in their April action the substantial reduction in business and operating risk of Duke Energy Carolinas from the distribution of its ownership in Spectra Energy Capital to a new holding company (New Duke Energy) and the substantial reduction in business and operating risk of Spectra Energy Capital through the restructuring of its ownership in DEFS and the divestiture of the former DENA merchant generation assets and trading book Moody's also noted the upgrade at Texas Eastern Transmission, LP in parallel to its parent Spectra Energy Capital

In August 2005, Moody's concluded a review of M&N Pipeline and downgraded the credit ratings one ratings level to A2 concluding this action with a stable outlook Moody's action was primarily as a result of their concerns over the downward revisions in the reserve estimates for the Sable Offshore Energy Project (SOEI) and reduced production by SOEI producers In August 2006, Moody's revised the outlook for Maritimes & Northeast Pipeline, LLC to negative, noting the potential for a somewhat weaker shipper profile resulting from a recently announced expansion project on the U S portion of the pipeline

The most recent rating action by DBRS occurred in June 2006 when DBRS confirmed the stable trend of Westcoast, Union Gas and M&N Pipeline following Duke Energy's announcement of the separation of the electric and gas businesses Each of the credit ratings assigned by DBRS to these entities has remained unchanged for the last several years with a stable trend

The following table summarizes the February 1, 2007 credit ratings from the agencies retained by Duke Energy, its principal funding subsidiaries and Duke Energy's trading and marketing subsidiary DETM

Credit Ratings Summary as of February 1, 2007

	Standard and Poor's	Moody's Investor Service
Duke Energy[(a)]	BBB	Baa2
Duke Energy Carolinas, LLC[(b)]	BBB	A3
Cinergy[(b)]	BBB-	Baa2
Duke Energy Ohio, Inc [(b)]	BBB	Baa1
Duke Energy Indiana, Inc.[(b)]	BBB	Baa1
Duke Energy Kentucky, Inc [(b)]	BBB	Baa1
Duke Energy Trading and Marketing, LLC[(c)]	BBB-	Not applicable

(a) Represents corporate credit rating and issuer rating for S&P and Moody's respectively

(b) Represents senior unsecured credit rating

(c) Represents corporate credit rating

These entities credit ratings are dependent upon, among other factors, the ability to generate sufficient cash to fund capital and investment expenditures, while maintaining the strength of their current balance sheets These credit ratings could be negatively impacted if as a result of market conditions or other factors, these entities are unable to maintain their current balance sheet strength, or if earnings and cash flow outlook materially deteriorates

During the third quarter of 2005, the Board of Directors of Duke Energy authorized and directed management to execute the sale or disposition of substantially all of former DENA's remaining assets and contracts outside the Midwestern United States On November 18, 2005, Duke Energy announced it signed an agreement to transfer substantially all of the former DENA portfolio of derivatives contracts to Barclays Under the agreement, Barclays acquired substantially all of former DENA's outstanding gas and power derivatives contracts which essentially eliminated Duke Energy's credit, collateral, market and legal risk associated with former DENA's derivative trading positions effective on the date of signing Substantially all of the underlying contracts have been transferred to Barclays

Duke Energy operated a commercial marketing and trading business that was acquired as part of the merger with Cinergy in April 2006 In June 2006, Duke Energy announced it had reached an agreement to sell Cinergy's commercial marketing and trading business, as well as associated contracts The sale closed in October 2006 and, upon closing, the buyer assumed the credit, collateral, market and legal risk associated with the trading positions acquired

A reduction in the credit rating of Duke Energy to below investment grade as of December 31, 2006 would have resulted in Duke Energy posting additional collateral of up to approximately $377 million, including impacts of Cinergy and excluding any collateral requirements associated with the spin-off of the natural gas businesses in January 2007 The majority of this collateral is related to outstanding surety bonds

Duke Energy would fund any additional collateral requirements through a combination of cash on hand and the use of credit facilities Additionally, if credit ratings for Duke Energy or its affiliates fall below investment grade there is likely to be a negative impact on its working capital and terms of trade that is not possible to fully quantify, in addition to the posting of additional collateral and segregation of cash described above

Clauses Duke Energy may be required to repay certain debt should the credit ratings of Duke Energy Carolinas fall to a certain level at S&P or Moody's. As of December 31, 2006, Duke Energy had $13 million of senior unsecured notes which mature serially through 2012 that may be required to be repaid if Duke Energy Carolinas' senior unsecured debt ratings fall below BBB- at S&P or Baa3 at Moody's, and $23 million of senior unsecured notes which mature serially through 2016 that may be required to be repaid if Duke Energy Carolinas' senior unsecured debt ratings fall below BBB at S&P or Baa2 at Moody's

Other Financing Matters. As of December 31, 2006, Duke Energy and its subsidiaries had effective SEC shelf registrations for up to $2,467 million in gross proceeds from debt and other securities, which include approximately $925 million of effective registrations at legacy Cinergy Additionally, as of December 31, 2006, Duke Energy had 935 million Canadian dollars (approximately U S $807 million) available under Canadian shelf registrations for issuances in the Canadian market. Of the 935 million Canadian dollars available under Canadian shelf registrations, 500 million expires in May 2008 and 435 million expires in August 2008 Amounts available under U S. and Canadian shelf registrations of approximately $592 million and 935 million Canadian dollars, respectively, relate to businesses included in the spin-off of the natural gas businesses on January 2, 2007 and, accordingly, are not available to Duke Energy subsequent to the consummation of the spin-off

Duke Energy expects to continue its policy of paying regular cash dividends There is no assurance as to the amount of future dividends because they depend on future earnings, capital requirements, and financial condition. Duke Energy has paid quarterly cash dividends for 81 consecutive years Dividends on common and preferred stocks in 2007 are expected to be paid on March 15, June 18, September 17 and December 17, subject to the discretion of the Board of Directors

Prior to June 2004, Duke Energy's Investor Direct Choice Plan allowed investors to reinvest dividends in common stock and to purchase common stock directly from Duke Energy In June 2004, Duke Energy changed the method of dividend reinvestment to open market purchases. There were no issuances of common stock under the plan in either 2006 or 2005. Issuances of common stock under the plan were $36 million in 2004

Duke Energy also sponsors an employee savings plan that covers substantially all U S employees In April 2004, Duke Energy stopped issuing shares under the plan and the plan began making open market purchases with cash provided by Duke Energy. There were no issuances of common stock under the plan in 2006 or 2005 Issuances of common stock under the plan were $51 million in 2004 Duke Energy also issues shares of its common stock to meet other employee benefit requirements Issuances of common stock to meet other employee benefit requirements were approximately $126 million in 2006, approximately $39 million for 2005 and approximately $12 million for 2004

Off-Balance Sheet Arrangements

Duke Energy and certain of its subsidiaries enter into guarantee arrangements in the normal course of business to facilitate commercial transactions with third parties These arrangements include financial and performance guarantees, stand-by letters of credit, debt guarantees, surety bonds and indemnifications These arrangements are largely entered into by Duke Energy, Spectra Energy Capital and Cinergy (See Note 18 to the Consolidated Financial Statements, "Guarantees and Indemnifications," for further details of the guarantee arrangements)

Most of the guarantee arrangements entered into by Duke Energy enhance the credit standing of certain subsidiaries, non-consolidated entities or less than wholly owned entities, enabling them to conduct business As such, these guarantee arrangements involve elements of performance and credit risk, which are not included on the Consolidated Balance Sheets The possibility of Duke Energy, Spectra Energy Capital or Cinergy having to honor its contingencies is largely dependent upon the future operations of the subsidiaries, investees and other third parties, or the occurrence of certain future events

Issuance of these guarantee arrangements is not required for the majority of Duke Energy's operations Thus, if Duke Energy discontinued issuing these guarantee arrangements, there would not be a material impact to the consolidated results of operations, cash flows or financial position

In contemplation of the spin-off of the natural gas businesses on January 2, 2007, certain guarantees that were previously issued by Spectra Energy Capital were transferred to Duke Energy prior to the consummation of the spin-off This resulted in Duke Energy recording an immaterial liability for certain guarantees that were previously grandfathered under the provisions of FIN 45 and, therefore, were not recognized in the Consolidated Balance Sheets Guarantees issued by Spectra Energy Capital or Natural Gas Transmission on or prior to December 31, 2006 remained with Spectra Energy Capital subsequent to the spin-off, except for certain guarantees that are in the process of being assigned to Duke Energy During this assignment period, Duke Energy has indemnified Spectra Energy Capital against any losses incurred under these guarantee obligations

Duke Energy Ohio, Duke Energy Indiana and Duke Energy Kentucky have an agreement to sell certain of their accounts receivable and related collections Cinergy formed Cinergy Receivables to purchase, on a revolving basis, nearly all of the retail accounts receivable and related collections of Duke Energy Ohio, Duke Energy Indiana and Duke Energy Kentucky. Cinergy does not consolidate Cinergy Receivables since it meets the requirements to be accounted for as a qualifying special purpose entity (SPE) Duke Energy Ohio, Duke Energy Indiana and Duke Energy Kentucky each retain an interest in the receivables transferred to Cinergy Receivables The transfers of receivables are accounted for as sales, pursuant to SFAS No 140,"*Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities.*" For a more detailed discussion of our sales of accounts receivable, see Note 23 to the Consolidated Financial Statements, "Variable Interest Entities"

Cinergy holds interests in variable interest entities (VIEs), consolidated and unconsolidated, as defined by FASB Interpretation No 46, "*Consolidation of Variable Interest Entities*" For further information, see Note 1 to the Consolidated Financial Statements, "Summary of Significant Accounting Policies"

Duke Energy does not have any other material off-balance sheet financing entities or structures, except for normal operating lease arrangements and guarantee arrangements (For additional information on these commitments, see Note 17 to the Consolidated Financial Statements, "Commitments and Contingencies" and Note 18 to the Consolidated Financial Statements, "Guarantees and Indemnifications")

Contractual Obligations

Duke Energy enters into contracts that require payment of cash at certain specified periods, based on certain specified minimum quantities and prices The following table summarizes Duke Energy's contractual cash obligations for each of the periods presented The table below excludes all amounts classified as current liabilities on the Consolidated Balance Sheets, other than current maturities of long-term debt, as well as future obligations of businesses included in the spin-off of Spectra Energy on January 2, 2007 It is expected that the majority of current liabilities on the Consolidated Balance Sheets will be paid in cash in 2007

PART II

Contractual Obligations as of December 31, 2006

	Payments Due By Period				
	Total	Less than 1 year (2007)	2-3 Years (2008 & 2009)	4-5 Years (2010 & 2011)	More than 5 Years (Beyond 2012)
			(in millions)		
Long-term debt[a]	$ 17,879	$ 1,695	$ 3,504	$ 1,749	$ 10,931
Capital leases[a]	113	15	36	25	37
Operating leases[b]	522	86	150	101	185
Purchase Obligations:[g]					
Firm capacity payments[c]	51	18	18	15	—
Energy commodity contracts[d]	5,189	1,872	1,901	918	498
Other purchase obligations[e]	2,065	912	778	39	336
Other long-term liabilities on the Consolidated Balance Sheets[f]	4,724	425	816	908	2,575
Total contractual cash obligations	$ 30,543	$ 5,023	$ 7,203	$ 3,755	$ 14,562

(a) See Note 15 to the Consolidated Financial Statements, "Debt and Credit Facilities" Amount includes interest payments over life of debt or capital lease

(b) See Note 17 to the Consolidated Financial Statements, "Commitments and Contingencies"

(c) Includes firm capacity payments that provide Duke Energy with uninterrupted firm access to electricity transmission capacity, refining capacity and the option to convert natural gas to electricity at third-party owned facilities (tolling arrangements) in some power locations throughout North America Also includes firm capacity payments under electric power agreements entered into to meet U S Franchised Electric and Gas' native load requirements

(d) Includes contractual obligations to purchase physical quantities of electricity, coal and nuclear fuel Amount includes certain normal purchases, energy derivatives and hedges per SFAS No 133 For contracts where the price paid is based on an index, the amount is based on forward market prices at December 31, 2006 For certain of these amounts, Duke Energy may settle on a net cash basis since Duke Energy has entered into payment netting agreements with counterparties that permit Duke Energy to offset receivables and payables with such counterparties

(e) Includes U S Franchised Electric and Gas' obligation to purchase an additional ownership interest in the Catawba Nuclear Station (see Note 5 to the Consolidated Financial Statements, "Joint Ownership of Generating and Transmission Facilities"), as well as contracts for software, telephone, data and consulting or advisory services Amount also includes contractual obligations for engineering, procurement and construction costs for nuclear plant refurbishments, environmental projects on fossil facilities, pipeline and real estate projects, and major maintenance of certain merchant plants Amount excludes certain open purchase orders for services that are provided on demand, and the timing of the purchase can not be determined

(f) Includes expected retirement plan contributions for 2007 (see Note 22 to the Consolidated Financial Statements, "Employee Benefit Plans"), certain estimated executive benefits, and contributions to the NDTF (see Note 7 to the Consolidated Financial Statements, "Asset Retirement Obligations") The amount of cash flows to be paid to settle the asset retirement obligations is not known with certainty as Duke Energy may use internal resources or external resources to perform retirement activities As a result, cash obligations for asset retirement activities are excluded Asset retirement obligations recognized on the Consolidated Balance Sheets total $2,301 million and the fair value of the NDTF, which will be used to help fund these obligations, is $1,775 million at December 31, 2006 Amount excludes reserves for litigation, environmental remediation, asbestos-related injuries and damages claims and self-insurance claims (see Note 17 to the Consolidated Financial Statements, "Commitments and Contingencies") because Duke Energy is uncertain as to the timing of when cash payments will be required Additionally, amount excludes annual insurance premiums that are necessary to operate the business, including nuclear insurance (see Note 17 to the Consolidated Financial Statements, "Commitments and Contingencies"), funding of other post-employment benefits (see Note 22 to the Consolidated Financial Statements, "Employee Benefit Plans") and regulatory credits (see Note 4 to the Consolidated Financial Statements, "Regulatory Matters") because the amount and timing of the cash payments are uncertain Also amount excludes Deferred Income Taxes and Investment Tax Credits on the Consolidated Balance Sheets since cash payments for income taxes are determined based primarily on taxable income for each discrete fiscal year Liabilities Associated with Assets Held for Sale (see Note 13 to the Consolidated Financial Statements, "Discontinued Operations and Assets Held for Sale") are also excluded as Duke Energy expects these liabilities will be assumed by the buyer upon sale of the assets

(g) Purchase obligations reflected in the Consolidated Balance Sheets have been excluded from the above table

Quantitative and Qualitative Disclosures About Market Risk

Risk and Accounting Policies

Duke Energy is exposed to market risks associated with commodity prices, credit exposure, interest rates, equity prices and foreign currency exchange rates Management has established comprehensive risk management policies to monitor and manage these market risks Duke Energy's Chief Executive Officer and Chief Financial Officer are responsible for the overall approval of market risk management policies and the delegation of approval and authorization levels The Finance and Risk Management Committee of the Board receives periodic updates from the Treasurer and other members of management, on market risk positions, corporate exposures, credit exposures and overall risk management activities The Treasurer is responsible for the overall governance of managing credit risk and commodity price risk, including monitoring exposure limits

See "Critical Accounting Policies—Risk Management Accounting and Revenue Recognition—Trading and Marketing Revenues" for further discussion of the accounting for derivative contracts

Disclosures about market risks related to businesses transferred to Spectra Energy in January 2007 are not reflected herein since such exposures have no impact on the ongoing operations of Duke Energy post spin-off

Commodity Price Risk

Duke Energy is exposed to the impact of market fluctuations in the prices of electricity, coal, natural gas and other energy-related products marketed and purchased as a result of its ownership of energy related assets Price risk represents the potential risk of loss from adverse changes in the market price of electricity or other energy commodities Duke Energy employs established policies and procedures to manage its risks associated with these market fluctuations using various commodity derivatives, including swaps, futures, forwards and options (See Note 1 to the Consolidated Financial Statements, "Summary of Significant Accounting Policies" and Note 8 to the Consolidated Financial Statements, "Risk Management and Hedging Activities, Credit Risk, and Financial Instruments ")

Validation of a contract's fair value is performed by an internal group independent of Duke Energy's deal origination areas While Duke Energy uses common industry practices to develop its valuation techniques, changes in Duke Energy's pricing methodologies or the underlying assumptions could result in significantly different fair values and income recognition

Hedging Strategies. Duke Energy closely monitors the risks associated with these commodity price changes on its future operations and, where appropriate, uses various commodity instruments such as electricity, coal and natural gas forward contracts to mitigate the effect of such fluctuations on operations Duke Energy's primary use of energy commodity derivatives is to hedge the output and production of assets

To the extent that instruments accounted for as hedges are effective in offsetting the transaction being hedged, there is no impact to the Consolidated Statements of Operations until delivery or settlement occurs Accordingly, assumptions and valuation techniques for these contracts have no impact on reported earnings prior to settlement Several factors influence the effectiveness of a hedge contract, including the use of contracts with different commodities or unmatched terms and counterparty credit risk. Hedge effectiveness is monitored regularly and measured each month (See Note 1 to the Consolidated Financial Statements, "Summary of Significant Accounting Policies" and Note 8 to the Consolidated Financial Statements, "Risk Management and Hedging Activities, Credit Risk, and Financial Instruments ")

In addition to the hedge contracts described above and recorded on the Consolidated Balance Sheets, Duke Energy enters into other contracts that qualify for the normal purchases and sales exception described in paragraph 10 of SFAS No 133, DIG Issue No C15 and SFAS No 149 For contracts qualifying for the scope exception, no recognition of the contract's fair value in the Consolidated Financial Statements is required until settlement of the contract unless the contract is designated as the hedged item in a fair value hedge On a limited basis, U S Franchised Electric and Gas and Commercial Power apply the normal purchase and normal sales exception to certain contracts Recognition for the contracts in the Consolidated Statements of Operations will be the same regardless of whether the contracts are accounted for as cash flow hedges or as normal purchases and sales, unless designated as the hedged item in a fair value hedge, assuming no hedge ineffectiveness

Income recognition and realization related to normal purchases and normal sales contracts generally coincide with the physical delivery of power However, Duke Energy's decisions in 2004 to sell former DENA Southeast Plants, reduce former DENA's interest in partially completed plants and sale or disposition of substantially all of former DENA's remaining physical and commercial assets outside of the Midwestern United States and certain contractual positions related to the Midwestern assets (see Normal Purchases and Normal Sales below) required the reassessment of all associated derivatives, including normal purchases and normal sales This required a change from the application of the Accrual Model to the MTM Model for these contracts and resulted in recording substantial unrealized losses that had not previously been recognized in the Consolidated Financial Statements

Generation Portfolio Risks Duke Energy is primarily exposed to market price fluctuations of wholesale power and natural gas prices in the U S Franchised Electric and Gas and Commercial Power segments Duke Energy optimizes the value of its bulk power marketing and non-regulated generation portfolios The portfolios include generation assets (power and capacity), fuel, and emission allowances Modeled forecasts of future generation output, fuel requirements, and emission allowance requirements are based on forward power, fuel and emission allowance markets The component pieces of the portfolio are bought and sold based on this model in order to manage the economic value of the portfolio, where such market transparency exists The generation portfolio not utilized to serve native load or committed load is subject to commodity price fluctuations Based on a sensitivity analysis as of December 31, 2006 and 2005, it was estimated that a ten percent price change per mega-watt hour in wholesale power prices would have a corresponding effect on Duke Energy's pre-tax income of approximately $30 million in 2007 and $20 million in 2006, respectively Based on a sensitivity analysis as of December 31, 2006, it was estimated that a ten percent price change per MMBtu in natural gas prices would have a corresponding effect on Duke Energy's pre-tax income of approximately $15 million in 2007

PART II

Normal Purchases and Normal Sales During the third quarter of 2005, Duke Energy's Board of Directors authorized and directed management to execute the sale or disposition of substantially all of former DENA's remaining assets and contracts outside the Midwestern United States, approximately 6,100 megawatts of power generation, and certain contractual positions related to the Midwestern assets (see Note 13 to the Consolidated Financial Statements, "Discontinued Operations and Assets Held for Sale") As a result of this decision, Duke Energy recognized a pre-tax loss of approximately $1.9 billion in the third quarter of 2005 for the disqualification of its power and gas forward sales contracts previously designated under the normal purchases normal sales exception This loss is partially offset by the recognition of a pre-tax gain of approximately $1 2 billion for the discontinuance of hedge accounting for natural gas and power cash flow hedges Duke Energy has retained the Midwestern generation assets in the Commercial Power segment, representing approximately 3,600 megawatts of power generation (see Note 2 to the Consolidated Financial Statements, "Acquisitions and Dispositions" for further details on the completed Cinergy merger)

Trading and Undesignated Contracts The risk in the trading portfolio is measured and monitored on a daily basis utilizing a Value-at-Risk (VaR) model to determine the potential one-day favorable or unfavorable VaR calculation Duke Energy's VaR amounts for commodity derivatives recorded using the MTM Model are not material as a result of management decisions to dispose of certain businesses with higher risk profiles, including the former DENA operations outside the Midwestern United States and the Cinergy commercial marketing and trading businesses In connection with the effort to reduce the risk profile, during 2006 Duke Energy finalized the sale of the former DENA power generation fleet outside of the Midwest to LS Power and sold the Cinergy commercial marketing and trading business to Fortis Subsequent to the sales of both trading businesses, Duke Energy no longer uses VaR as a trading portfolio measure

Other Commodity Risks. Duke Energy, through Commercial Power, owns coal-based synthetic fuel production facilities which convert coal feedstock into synthetic fuel for sale to third parties. The synthetic fuel produced at these facilities qualifies for tax credits (through 2007) in accordance with Internal Revenue Code Section 29/45K if certain requirements are satisfied. The Internal Revenue Code provides for a phase-out of synthetic fuel tax credits if the average annual wellhead oil prices increase above certain levels If Commercial Power were to operate its synthetic fuel facilities based on December 31, 2006 prices throughout the entire forthcoming year, yet crude oil prices were to rise such that the tax credit is completely phased-out, projected net income in 2007 would be negatively impacted by approximately $100 million Duke Energy is unlikely to experience a loss of this magnitude because the exposure to synthetic fuel tax credit phase-out is monitored and Duke Energy may choose to reduce or cease synthetic fuel production depending on the expectation of any potential tax credit phase-out Duke Energy may also reduce its exposure to crude prices through the execution of derivative transactions The objective of these activities is to reduce potential losses incurred if the reference price in a year exceeds a level triggering a phase-out of synthetic fuel tax credits

Pre-tax income for 2007 or 2006 was also not expected to be materially impacted as of December 31, 2006 or 2005 for exposures to other commodities' price changes These hypothetical calculations consider existing hedge positions and estimated production levels, but do not consider other potential effects that might result from such changes in commodity prices

Duke Energy's exposure to commodity price risk is influenced by a number of factors, including contract size, length, market liquidity, location and unique or specific contract terms

Credit Risk

Credit risk represents the loss that Duke Energy would incur if a counterparty fails to perform under its contractual obligations To reduce credit exposure, Duke Energy seeks to enter into netting agreements with counterparties that permit Duke Energy to offset receivables and payables with such counterparties. Duke Energy attempts to further reduce credit risk with certain counterparties by entering into agreements that enable Duke Energy to obtain collateral or to terminate or reset the terms of transactions after specified time periods or upon the occurrence of credit-related events Duke Energy may, at times, use credit derivatives or other structures and techniques to provide for third-party credit enhancement of Duke Energy's counterparties' obligations.

Duke Energy's principal customers for power and natural gas marketing and transportation services are industrial end-users, marketers, local distribution companies and utilities located throughout the U S , Canada and Latin America Duke Energy has concentrations of receivables from natural gas and electric utilities and their affiliates, as well as industrial customers and marketers throughout these regions These concentrations of customers may affect Duke Energy's overall credit risk in that risk factors can negatively impact the credit quality of the entire sector Where exposed to credit risk, Duke Energy analyzes the counterparties' financial condition prior to entering into an agreement, establishes credit limits and monitors the appropriateness of those limits on an ongoing basis

The following table represents Duke Energy's distribution of unsecured credit exposures at December 31, 2006, including Spectra Energy businesses These credit exposures are aggregated by ultimate parent company, include on and off balance sheet exposures, are presented net of collateral, and take into account contractual netting rights

Distribution of Enterprise Credit Exposures
As of December 31, 2006

	% of Total
Investment Grade—Externally Rated	75%
Non-Investment Grade—Externally Rated	7
Investment Grade—Internally Rated	8
Non-Investment Grade—Internally Rated	10
Total	100%

"Externally Rated" represents enterprise relationships that have published ratings from at least one major credit rating agency "Internally Rated" represents those relationships which have no rating by a major credit rating agency For those relationships, Duke Energy utilizes appropriate risk rating methodologies and credit scoring models to develop an internal risk rating which is intended to map to an external rating equivalent The total of the unsecured credit exposure included in the table above represents approximately 59% of the gross fair value of Duke Energy's Receivables and Unrealized Gains on Mark-to-Market and Hedging Transactions on the Consolidated Balance Sheets at December 31, 2006

Duke Energy had no net exposure to any one customer that represented greater than 10% of the gross fair value of trade accounts receivable and unrealized gains on mark-to-market and hedging transactions at December 31, 2006 Excluding the businesses transferred to Spectra Energy in January 2007, the split between investment grade and non-investment grade would have been approximately 70% and 30%, respectively Based on Duke Energy's policies for managing credit risk, its exposures and its credit and other reserves, Duke Energy does not anticipate a materially adverse effect on its consolidated financial position or results of operations as a result of non-performance by any counterparty.

During 2006, Duke Energy finalized the sale of the former DENA portfolio of derivative contracts to Barclays and sold the Cinergy commercial marketing and trading business to Fortis, which eliminated Duke Energy's credit, collateral, market and legal risk associated with these related trading positions

In 1999, the Industrial Development Corp of the City of Edinburg, Texas (IDC) issued approximately $100 million in bonds to purchase equipment for lease to Duke Hidalgo (Hidalgo), a subsidiary of Spectra Energy Capital Spectra Energy Capital unconditionally and irrevocably guaranteed the lease payments of Hidalgo to IDC through 2028 In 2000, Hidalgo was sold to Calpine Corporation and Spectra Energy Capital remained obligated under the lease guaranty In January 2006, Hidalgo and its subsidiaries filed for bankruptcy protection in connection with the previous bankruptcy filing by its parent, Calpine Corporation in December 2005 Gross, undiscounted exposure under the guarantee obligation as of December 31, 2006 is approximately $200 million, including principal and interest payments Duke Energy does not believe a loss under the guarantee obligation is probable as of December 31, 2006, but continues to evaluate the situation Therefore, no reserves have been recorded for any contingent loss as of December 31, 2006 No demands for payment have been made under the guarantee If losses are incurred under the guarantee, Spectra Energy Capital has certain rights which should allow it to mitigate such loss Subsequent to the spin-off the natural gas businesses, this guarantee remained with Spectra Energy Capital However, Duke Energy indemnified Spectra Energy Capital against any future losses that could arise from payments required under this guarantee

Duke Energy's industry has historically operated under negotiated credit lines for physical delivery contracts. Duke Energy frequently uses master collateral agreements to mitigate certain credit exposures The collateral agreements provide for a counterparty to post cash or letters of credit to the exposed party for exposure in excess of an established threshold. The threshold amount represents an unsecured credit limit, determined in accordance with the corporate credit policy Collateral agreements also provide that the inability to post collateral is sufficient cause to terminate contracts and liquidate all positions

Duke Energy also obtains cash or letters of credit from customers to provide credit support outside of collateral agreements, where appropriate, based on its financial analysis of the customer and the regulatory or contractual terms and conditions applicable to each transaction

PART II

Collateral amounts held or posted may be fixed or may vary depending on the terms of the collateral agreement and the nature of the underlying exposure and cover normal purchases and normal sales, hedging contracts, and optimization contracts outstanding Duke Energy may be required to return certain held collateral and post additional collateral should price movements adversely impact the value of open contracts or positions In many cases, Duke Energy's and its counterparties' publicly disclosed credit ratings impact the amounts of additional collateral to be posted If Duke Energy or its affiliates have a credit rating downgrade, it could result in reductions in Duke Energy's unsecured thresholds granted by counterparties. Likewise, downgrades in credit ratings of counterparties could require counterparties to post additional collateral to Duke Energy and its affiliates (See "Liquidity and Capital Resources—Financing Cash Flows and Liquidity" for additional discussion of downgrades)

Interest Rate Risk

Duke Energy is exposed to risk resulting from changes in interest rates as a result of its issuance of variable and fixed rate debt and commercial paper Duke Energy manages its interest rate exposure by limiting its variable-rate exposures to percentages of total capitalization and by monitoring the effects of market changes in interest rates Duke Energy also enters into financial derivative instruments, including, but not limited to, interest rate swaps, swaptions and U S Treasury lock agreements to manage and mitigate interest rate risk exposure (See Notes 1, 8, and 15 to the Consolidated Financial Statements, "Summary of Significant Accounting Policies," "Risk Management and Hedging Activities, Credit Risk, and Financial Instruments," and "Debt and Credit Facilities ")

~~Based on a sensitivity analysis as of December 31, 2006, it was estimated that if market interest rates average 1% higher (lower) in 2007 than in 2006, interest expense, net of offsetting~~ impacts in interest income, would increase (decrease) by approximately $3 million, excluding interest rate risk related to businesses transferred to Spectra Energy in January 2007. Comparatively, based on a sensitivity analysis as of December 31, 2005, had interest rates averaged 1% higher (lower) in 2006 than in 2005, it was estimated that interest expense, net of offsetting impacts in interest income, would have increased (decreased) by approximately $9 million These amounts were estimated by considering the impact of the hypothetical interest rates on variable-rate securities outstanding, adjusted for interest rate hedges, short-term investments, cash and cash equivalents outstanding as of December 31, 2006 and 2005 The decrease in interest rate sensitivity was primarily due to the exclusion of interest rate risk, principally subsidiary debt and swaps, related to businesses transferred to Spectra Energy If interest rates changed significantly, management would likely take actions to manage its exposure to the change However, due to the uncertainty of the specific actions that would be taken and their possible effects, the sensitivity analysis assumes no changes in Duke Energy's financial structure

Equity Price Risk

Duke Energy maintains trust funds, as required by the NRC and the NCUC, to fund the costs of nuclear decommissioning (See Note 7 to the Consolidated Financial Statements, "Asset Retirement Obligations ") As of December 31, 2006 and 2005, these funds were invested primarily in domestic and international equity securities, fixed-rate, fixed-income securities and cash and cash equivalents. Per NRC and NCUC requirements, these funds may be used only for activities related to nuclear decommissioning Those investments are exposed to price fluctuations in equity markets and changes in interest rates Accounting for nuclear decommissioning recognizes that costs are recovered through U S Franchised Electric and Gas' rates, and fluctuations in equity prices or interest rates do not affect Duke Energy's consolidated results of operations Earnings or losses of the fund will ultimately impact the amount of costs recovered from U S Franchised Electric and Gas' rates

Bison, Duke Energy's wholly owned captive insurance subsidiary, maintains investments to fund various business risks and losses, such as workers compensation, property, business interruption and general liability Those investments are exposed to price fluctuations in equity markets and changes in interest rates

Duke Energy's costs of providing non-contributory defined benefit retirement and postretirement benefit plans are dependent upon a number of factors, such as the rates of return on plan assets, discount rate, the rate of increase in health care costs and contributions made to the plans

Foreign Currency Risk

Duke Energy is exposed to foreign currency risk from investments in international affiliate businesses owned and operated in foreign countries and from certain commodity-related transactions within domestic operations To mitigate risks associated with foreign currency fluctuations, contracts may be denominated in or indexed to the U.S Dollar and/or local inflation rates, or investments may be naturally hedged through debt denominated or issued in the foreign currency Duke Energy may also use foreign currency derivatives, where possible, to manage its risk related to foreign currency fluctuations To monitor its currency exchange rate risks, Duke Energy uses sensitivity analysis, which measures the impact of devaluation of the foreign currencies to which it has exposure

In 2007, Duke Energy's primary foreign currency rate exposures are expected to be the Brazilian Real and the Peruvian New Sol A 10% devaluation in the currency exchange rates as of December 31, 2006 in all of Duke Energy's exposure currencies would result in an estimated net pre-tax loss on the translation of local currency earnings of approximately $7 million to Duke Energy's Consolidated Statements of Operations in 2007 The Consolidated Balance Sheet would be negatively impacted by approximately $120 million currency translation through the cumulative translation adjustment in AOCI as of December 31, 2006 as a result of a 10% devaluation in the currency exchange rates

OTHER ISSUES

Spin-off of the Natural Gas Businesses. In June 2006, the Board of Directors of Duke Energy authorized management to pursue a plan to create two separate publicly traded companies by spinning off Duke Energy's natural gas businesses to Duke Energy shareholders The spin-off was effective January 2, 2007 The new natural gas company, which is named Spectra Energy, principally consists of Duke Energy's Natural Gas Transmission business segment, which includes Union Gas, and also includes Duke Energy's 50% ownership interest in DEFS Approximately $20 billion of assets, $13 billion of liabilities (which includes approximately $8 6 billion of debt issued by Spectra Energy Capital and its consolidated subsidiaries) and $7 billion of common stockholders' equity were distributed from Duke Energy as of the date of the spin-off Assets and liabilities of entities included in the spin-off of Spectra Energy were transferred from Duke Energy on a historical cost basis on the date of the spin-off transaction As a result of the spin-off transaction, on January 2, 2007, in lieu of adjusting the conversion ratio of the convertible debt, Duke Energy issued approximately 2 4 million shares of Spectra Energy common stock to holders of Duke Energy's convertible senior notes due 2023, consistent with the terms of the debt agreements. The issuance of Spectra Energy shares to the convertible debt holders is expected to result in a pretax charge in the range of $20 million to $30 million in Duke Energy's 2007 consolidated statement of operations The historical results of the natural gas businesses are expected to be treated as discontinued operations at Duke Energy in future periods beginning with the first quarter of 2007 The primary businesses remaining in Duke Energy post-spin are the U S Franchised Electric and Gas business segment, the Commercial Power business segment, the International Energy business segment and Duke Energy's effective 50% interest in the Crescent JV The decision to spin off the natural gas business is expected to deliver long-term value to shareholders

Energy Policy Act of 2005. The Energy Policy Act of 2005 was signed into law in August 2005 The legislation directs specified agencies to conduct a significant number of studies on various aspects of the energy industry and to implement other provisions through rulemakings Among the key provisions, the Energy Policy Act of 2005 repeals the PUHCA of 1935, directs FERC to establish a self-regulating electric reliability organization governed by an independent board with FERC oversight, extends the Price Anderson Act for 20 years (until 2025), provides loan guarantees, standby support and production tax credits for new nuclear reactors, gives FERC enhanced merger approval authority, provides FERC new backstop authority for the siting of certain electric transmission projects, streamlines the processes for approval and permitting of interstate pipelines, and reforms hydropower relicensing FERC's enhanced merger authority will not apply to transactions pending with the FERC as of August 8, 2005, such as the Duke Energy and Cinergy merger, as discussed in Note 2 to the Consolidated Financial Statements, "Acquisitions and Dispositions " In late 2005 and early 2006, FERC initiated several rulemakings as directed by the Energy Policy Act of 2005 Duke Energy is currently evaluating these proposals and does not anticipate that these rulemakings will have a material adverse effect on its consolidated results of operations, cash flows or financial position

Global Climate Change. The greenhouse gas policy of the United States currently favors voluntary actions to reduce emissions and continued research and technology development over near-term mandatory greenhouse gas emission reduction requirements Although several bills have been introduced in Congress that would mandate greenhouse gas emission reductions, none have advanced through the legislature and presently there are no federal mandatory greenhouse gas reduction requirements While it is possible that Congress will adopt some form of mandatory greenhouse gas emission reduction legislation in the future, the timing and specific requirements of any such legislation are highly uncertain Several Northeastern states and California are in the process of developing their own mandatory greenhouse gas emission reduction programs; none of which will impact Duke Energy's operations

Duke Energy supports the enactment of U S federal legislation that would require a gradual transition to a lower carbon-intensive economy Legislation preferably would be in the form of a federal-level carbon tax or cap-and-trade based program Duke Energy, believing that it is in the best interest of its investors and customers to do so, is actively participating in the evolution of federal policy on this important issue

Duke Energy's proactive role in climate change policy debates in the United States does not change the uncertainty around such policy Due to the speculative outlook regarding U S federal policy, Duke Energy cannot estimate the potential effect of future U S greenhouse gas policy on its future consolidated results of operations, cash flows or financial position Duke Energy will assess and respond to the potential implications of U S greenhouse gas policy for its business operations if policy becomes sufficiently developed and certain to support a meaningful assessment

This disclosure related to the global climate change excludes developments in Canada due to the spin-off of Duke Energy's natural gas businesses on January 2, 2007

(For additional information on other issues related to Duke Energy, see Note 4 to the Consolidated Financial Statements, "Regulatory Matters" and Note 17 to the Consolidated Financial Statements, "Commitments and Contingencies.")

New Accounting Standards

The following new accounting standards have been issued, but have not yet been adopted by Duke Energy as of December 31, 2006:

SFAS No. 155, "Accounting for Certain Hybrid Financial Instruments—an amendment of FASB Statements No. 133 and 140" (SFAS No. 155). In February 2006, the FASB issued SFAS No 155, which amends *SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities"* and *SFAS No. 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities" (SFAS* No 140). SFAS No 155 allows financial instruments that have embedded derivatives to be accounted for at fair value at acquisition, at issuance, or when a previously recognized financial instrument is subject to a remeasurement (new basis) event, on an instrument-by-instrument basis, in cases in which a derivative would otherwise have to be bifurcated. SFAS No 155 is effective for Duke Energy for all financial instruments acquired, issued, or subject to remeasurement after January 1, 2007, and for certain hybrid financial instruments that have been bifurcated prior to the effective date, for which the effect is to be reported as a cumulative-effect adjustment to beginning retained earnings. Duke Energy does not anticipate the adoption of SFAS No 155 will have any material impact on its consolidated results of operations, cash flows or financial position

SFAS No. 156, "Accounting for Servicing of Financial Assets—an amendment of FASB Statement No. 140" (SFAS No. 156). In March 2006, the FASB issued SFAS No 156, which amends SFAS No 140 SFAS No 156 requires recognition of a servicing asset or liability when an entity enters into arrangements to service financial instruments in certain situations. Such servicing assets or servicing liabilities are required to be initially measured at fair value, if practicable SFAS No 156 also allows an entity to subsequently measure its servicing assets or servicing liabilities using either an amortization method or a fair value method. SFAS No 156 is effective for Duke Energy as of January 1, 2007, and must be applied prospectively, except that where an entity elects to remeasure separately recognized existing arrangements and reclassify certain available-for-sale securities to trading securities, any effects must be reported as a cumulative-effect adjustment to retained earnings. Duke Energy does not anticipate the adoption of SFAS No 156 will have any material impact on its consolidated results of operations, cash flows or financial position

SFAS No. 157, "Fair Value Measurements" (SFAS No. 157). In September 2006, the FASB issued SFAS No 157, which defines fair value, establishes a framework for measuring fair value in GAAP, and expands disclosures about fair value measurements SFAS No 157 does not require any new fair value measurements However, in some cases, the application of SFAS No 157 may change Duke Energy's current practice for measuring and disclosing fair values under other accounting pronouncements that require or permit fair value measurements For Duke Energy, SFAS No 157 is effective as of January 1, 2008 and must be applied prospectively except in certain cases Duke Energy is currently evaluating the impact of adopting SFAS No 157, and cannot currently estimate the impact of SFAS No 157 on its consolidated results of operations, cash flows or financial position

SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities" (SFAS No. 159). In February 2007, the FASB issued SFAS No 159, which permits entities to choose to measure many financial instruments and certain other items at fair value For Duke Energy, SFAS No 159 is effective as of January 1, 2008 and will have no impact on amounts presented for periods prior to the effective date Duke Energy cannot currently estimate the impact of SFAS No 159 on its consolidated results of operations, cash flows or financial position and has not yet determined whether or not it will choose to measure items subject to SFAS No 159 at fair value

FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes—an interpretation of FASB Statement No. 109" (FIN 48). In July 2006, the FASB issued FIN 48, which provides guidance on accounting for income tax positions about which Duke Energy has concluded there is a level of uncertainty with respect to the recognition in Duke Energy's financial statements FIN 48 prescribes a minimum recognition threshold a tax position is required to meet. Tax positions are defined very broadly and include not only tax deductions and credits but also decisions not to file in a particular jurisdiction, as well as the taxability of transactions. Duke Energy will implement FIN 48 effective January 1, 2007 The implementation is expected to result in a cumulative effect adjustment to beginning Retained Earnings on the Consolidated Statement of Common Stockholders' Equity and Comprehensive Income (Loss) in the first quarter 2007 in the range of $15 million to $30 million. Corresponding entries will impact a variety of balance sheet line items, including Deferred Income Taxes, Taxes Accrued, Other Liabilities, and Goodwill Upon implementation of FIN 48, Duke Energy will reflect interest expense related to taxes as Interest Expense, in the Consolidated Statement of Operations In addition, subsequent accounting for FIN 48 (after January 1, 2007) will involve an evaluation to determine if any changes have occurred that would impact the existing uncertain tax positions as well as

PART II

determining whether any new tax positions are uncertain Any impacts resulting from the evaluation of existing uncertain tax positions or from the recognition of new uncertain tax positions would impact income tax expense and interest expense in the Consolidated Statement of Operations, with offsetting impacts to the balance sheet line items described above Because of the spin-off of Spectra Energy in the first quarter of 2007, certain liabilities and deferred tax assets related to uncertain tax positions filed on Spectra Energy tax returns will be removed from Duke Energy's balance sheet Uncertain tax positions on consolidated or combined tax returns filed by Duke Energy which are indemnified by Spectra Energy will be recorded as receivables from Spectra Energy

FASB Staff Position (FSP) No. FAS 123(R)-5, "Amendment of FASB Staff Position FAS 123(R)-1" (FSP No. FAS 123(R)-5). In October 2006, the FASB staff issued FSP No FAS 123(R)-5 to address whether a modification of an instrument in connection with an equity restructuring should be considered a modification for purposes of applying *FSP No. FAS 123(R)-1, "Classification and Measurement of Freestanding Financial Instruments Originally Issued in Exchange for Employee Services under FASB Statement No. 123(R) (FSP No. FAS 123(R)-1)."* In August 2005, the FASB staff issued FSP FAS 123(R)-1 to defer indefinitely the effective date of paragraphs A230—A232 of SFAS No 123(R), and thereby require entities to apply the recognition and measurement provisions of SFAS No 123(R) throughout the life of an instrument, unless the instrument is modified when the holder is no longer an employee The recognition and measurement of an instrument that is modified when the holder is no longer an employee should be determined by other applicable generally accepted accounting principles FSP No FAS 123(R)-5 addresses modifications of stock-based awards made in connection with an equity restructuring and clarifies that for instruments that were originally issued as employee compensation and then modified, and that modification is made to the terms of the instrument solely to reflect an equity restructuring that occurs when the holders are no longer employees, no change in the recognition or the measurement (due to a change in classification) of those instruments will result if certain conditions are met. This FSP is effective for Duke Energy as of January 1, 2007 The impact to Duke Energy of applying FSP No FAS 123(R)-5 in subsequent periods will be dependent upon the nature of any modifications to Duke Energy's share-based compensation awards

FSP No. AUG AIR-1. "Accounting for Planned Major Maintenance Activities," (FSP AUG AIR-1). In September 2006, the FASB Staff issued FSP No AUG AIR-1 This FSP prohibits the use of the accrue-in-advance method of accounting for planned major maintenance activities in annual and interim financial reporting periods, if no liability is required to be recorded for an asset retirement obligation based on a legal obligation for which the event obligating the entity has occurred The FSP also requires disclosures regarding the method of accounting for planned major maintenance activities and the effects of implementing the FSP The guidance in this FSP is effective for Duke Energy as of January 1, 2007 and will be applied and retrospectively for all financial statements presented Duke Energy does not anticipate the adoption of FSP No AUG AIR-1 will have any material impact on its consolidated results of operations, cash flows or financial position

EITF Issue No. 06-3, "How Taxes Collected from Customers and Remitted to Governmental Authorities Should Be Presented in the Income Statement (That Is, Gross versus Net Presentation)" (EITF No. 06-3) In June 2006, the EITF reached a consensus on EITF No 06-3 to address any tax assessed by a governmental authority that is directly imposed on a revenue-producing transaction between a seller and a customer and may include, but are not limited to, sales, use, value added, and some excise taxes For taxes within the issue's scope, the consensus requires that entities present such taxes on either a gross (i e included in revenues and costs) or net (i e exclude from revenues) basis according to their accounting policies, which should be disclosed If such taxes are reported gross and are significant, entities should disclose the amounts of those taxes Disclosures may be made on an aggregate basis The consensus is effective for Duke Energy beginning January 1, 2007 Duke Energy does not anticipate the adoption of EITF No 06-3 will have any material impact on its consolidated results of operations, cash flows or financial position

EITF Issue No. 06-5, "Accounting for Purchases of Life Insurance—Determining the Amount That Could Be Realized in Accordance with FASB Technical Bulletin No. 85-4" (EITF No. 06-5) In June 2006, the EITF reached a consensus on the accounting for corporate-owned and bank-owned life insurance policies EITF No 06-5 requires that a policyholder consider the cash surrender value and any additional amounts to be received under the contractual terms of the policy in determining the amount that could be realized under the insurance contract. Amounts that are recoverable by the policyholder at the discretion of the insurance company must be excluded from the amount that could be realized Fixed amounts that are recoverable by the policyholder in future periods in excess of one year from the surrender of the policy must be recognized at their present value EITF No 06-5 is effective for Duke Energy as of January 1, 2007 and must be applied as a change in accounting principle through a cumulative-effect adjustment to retained earnings or other components of equity as of January 1, 2007 Duke Energy does not anticipate the adoption of EITF No 06-5 will have any material impact on its consolidated results of operations, cash flows or financial position

EITF Issue No. 06-6, "Debtor's Accounting for a Modification (or Exchange) of Convertible Debt Instruments" (EITF No. 06-6). In November 2006, the EITF reached a consensus on EITF No 06-6 EITF No 06-6 addresses how a modification of a debt instrument (or an exchange of debt instruments) that affects the terms of an embedded conversion option should be considered in the issuer's analysis of whether debt extinguishment accounting should be applied, and further addresses the accounting for a modification of a debt instrument (or an exchange of debt instruments) that affects the terms of an embedded conversion option when extinguishment accounting is not applied EITF No 06-6 applies to modifications (or exchanges) occurring in interim or annual reporting periods beginning after November 29, 2006, regardless of when the instrument was originally issued Early application is permitted for modifications (or exchanges) occurring in periods for which financial statements have not been issued There were no modifications to, or exchanges of, any of Duke Energy's debt instruments within the scope of EITF No 06-6 in 2006 EITF No 06-6 is effective for Duke Energy beginning January 1, 2007 The impact to Duke Energy of applying EITF No. 06-6 in subsequent periods will be dependent upon the nature of any modifications to, or exchanges of, any debt instruments within the scope of EITF No. 06-6 Refer to Note 15, "Debt and Credit Facilities "

Item 7A. Quantitative and Qualitative Disclosures About Market Risk.

See "Management's Discussion and Analysis of Results of Operations and Financial Condition, Quantitative and Qualitative Disclosures About Market Risk."

PART II

Item 8. Financial Statements and Supplementary Data.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of Duke Energy Corporation:

We have audited the accompanying consolidated balance sheets of Duke Energy Corporation and subsidiaries (the "Company") as of December 31, 2006 and 2005, and the related consolidated statements of operations, stockholders' equity and comprehensive income, and cash flows for each of the three years in the period ended December 31, 2006. Our audits also included the consolidated financial statement schedule listed in the Index at Item 15. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Duke Energy Corporation and subsidiaries as of December 31, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

As discussed in Note 1 to the consolidated financial statements, in 2006 the Company changed its method of accounting for defined benefit pension and other postretirement plans as a result of adopting Statement of Financial Accounting Standard No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans*.

As discussed in Notes 1 and 25 to the consolidated financial statements, the Company's spin-off of the natural gas businesses was completed on January 2, 2007.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Company's internal control over financial reporting as of December 31, 2006, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 1, 2007 expressed an unqualified opinion on management's assessment of the effectiveness of the Company's internal control over financial reporting and an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP

Charlotte, North Carolina
March 1, 2007

PART II

DUKE ENERGY CORPORATION
Consolidated Statements of Operations
(In millions, except per-share amounts)

	Years Ended December 31, 2006	2005	2004
Operating Revenues			
Non-regulated electric, natural gas, natural gas liquids, and other	$ 3,158	$ 7,212	$ 11,322
Regulated electric	7,678	5,406	5,041
Regulated natural gas and natural gas liquids	4,348	3,679	3,233
Total operating revenues	15,184	16,297	19,596
Operating Expenses			
Natural gas and petroleum products purchased	1,829	5,827	9,225
Operation, maintenance and other	4,415	3,540	3,313
Fuel used in electric generation and purchased power	3,403	1,610	1,576
Depreciation and amortization	2,049	1,728	1,750
Property and other taxes	769	571	513
Impairments and other charges	28	140	64
Total operating expenses	12,493	13,416	16,441
Gains on Sales of Investments in Commercial and Multi-Family Real Estate	201	191	192
Gains (Losses) on Sales of Other Assets and Other, net	276	534	(416)
Operating Income	3,168	3,606	2,931
Other Income and Expenses			
Equity in earnings of unconsolidated affiliates	732	479	161
(Losses) Gains on sales and impairments of equity investments	(20)	1,225	(4)
Gain on sale of subsidiary stock	15	—	—
Other income and expenses, net	281	105	147
Total other income and expenses	1,008	1,809	304
Interest Expense	1,253	1,066	1,282
Minority Interest Expense	61	538	200
Earnings From Continuing Operations Before Income Taxes	2,862	3,811	1,753
Income Tax Expense from Continuing Operations	843	1,282	507
Income From Continuing Operations	2,019	2,529	1,246
(Loss) Income From Discontinued Operations, net of tax	(156)	(701)	244
Income Before Cumulative Effect of Change in Accounting Principle	1,863	1,828	1,490
Cumulative Effect of Change in Accounting Principle, net of tax and minority interest	—	(4)	—
Net Income	1,863	1,824	1,490
Dividends and Premiums on Redemption of Preferred and Preference Stock	—	12	9
Earnings Available For Common Stockholders	$ 1,863	$ 1,812	$ 1,481
Common Stock Data			
Weighted-average shares outstanding			
Basic	1,170	934	931
Diluted	1,188	970	966
Earnings per share (from continuing operations)			
Basic	$ 1.73	$ 2.69	$ 1.33
Diluted	$ 1.70	$ 2.60	$ 1.29
(Loss) earnings per share (from discontinued operations)			
Basic	$ (0.14)	$ (0.75)	$ 0.26
Diluted	$ (0.13)	$ (0.72)	$ 0.25
Earnings per share (before cumulative effect of change in accounting principle)			
Basic	$ 1.59	$ 1.94	$ 1.59
Diluted	$ 1.57	$ 1.88	$ 1.54
Earnings per share			
Basic	$ 1.59	$ 1.94	$ 1.59
Diluted	$ 1.57	$ 1.88	$ 1.54
Dividends per share	$ 1.26	$ 1.17	$ 1.10

See Notes to Consolidated Financial Statements

PART II

DUKE ENERGY CORPORATION
Consolidated Balance Sheets
(In millions)

	December 31,	
	2006	2005
ASSETS		
Current Assets		
Cash and cash equivalents	$ 948	$ 511
Short-term investments	1,514	632
Receivables (net of allowance for doubtful accounts of $94 at December 31, 2006 and $127 at December 31, 2005)	2,256	2,580
Inventory	1,358	863
Assets held for sale	28	1,528
Unrealized gains on mark-to-market and hedging transactions	107	87
Other	729	1,756
Total current assets	6,940	7,957
Investments and Other Assets		
Investments in unconsolidated affiliates	2,305	1,933
Nuclear decommissioning trust funds	1,775	1,504
Goodwill	8,175	3,775
Intangibles, net	905	65
Notes receivable	224	138
Unrealized gains on mark-to-market and hedging transactions	248	62
Assets held for sale	134	3,597
Investments in residential, commercial and multi-family real estate (net of accumulated depreciation of $17 at December 31, 2005)	—	1,281
Other	2,304	2,678
Total investments and other assets	16,070	15,033
Property, Plant and Equipment		
Cost	58,330	40,823
Less accumulated depreciation and amortization	16,883	11,623
Net property, plant and equipment	41,447	29,200
Regulatory Assets and Deferred Debits		
Deferred debt expense	320	269
Regulatory assets related to income taxes	1,361	1,338
Other	2,562	926
Total regulatory assets and deferred debits	4,243	2,533
Total Assets	$ 68,700	$ 54,723

See Notes to Consolidated Financial Statements

Table of Contents

PART II

DUKE ENERGY CORPORATION

Consolidated Balance Sheets—(Continued)
(In millions, except per-share amounts)

	December 31,	
	2006	2005
LIABILITIES AND COMMON STOCKHOLDERS' EQUITY		
Current Liabilities		
Accounts payable	$ 1,686	$ 2,431
Notes payable and commercial paper	450	83
Taxes accrued	434	327
Interest accrued	302	230
Liabilities associated with assets held for sale	26	1,488
Current maturities of long-term debt	1,605	1,400
Unrealized losses on mark-to-market and hedging transactions	134	204
Other	1,976	2,255
Total current liabilities	6,613	8,418
Long-term Debt	18,118	14,547
Deferred Credits and Other Liabilities		
Deferred income taxes	7,003	5,253
Investment tax credit	175	144
Unrealized losses on mark-to-market and hedging transactions	238	10
Liabilities associated with assets held for sale	18	2,085
Asset retirement obligations	2,301	2,058
Other	7,327	5,020
Total deferred credits and other liabilities	17,062	14,570
Commitments and Contingencies		
Minority Interests	805	749
Common Stockholders' Equity		
Common stock, $0.001 par value, 2 billion shares authorized; 1,257 million and zero shares outstanding at December 31, 2006 and December 31, 2005, respectively	1	—
Common stock, no par, 2 billion shares authorized; zero and 928 million shares outstanding at December 31, 2006 and December 31, 2005, respectively	—	10,446
Additional paid-in capital	19,854	—
Retained earnings	5,652	5,277
Accumulated other comprehensive income	595	716
Total common stockholders' equity	26,102	16,439
Total Liabilities and Common Stockholders' Equity	$ 68,700	$ 54,723

See Notes to Consolidated Financial Statements

PART II

DUKE ENERGY CORPORATION
Consolidated Statements of Cash Flows
(In millions)

	Years Ended December 31,		
	2006	2005	2004
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$ 1,863	$ 1,824	$ 1,490
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization (including amortization of nuclear fuel)	2,215	1,884	2,037
Cumulative effect of change in accounting principle	—	4	—
Gains on sales of investments in commercial and multi-family real estate	(201)	(191)	(201)
Gains on sales of equity investments and other assets	(365)	(1,771)	(193)
Impairment charges	48	159	194
Deferred income taxes	250	282	867
Minority Interest	61	538	195
Equity in earnings of unconsolidated affiliates	(732)	(479)	(161)
Purchased capacity levelization	(14)	(14)	92
Contributions to company-sponsored pension plans	(172)	(45)	(279)
(Increase) decrease in			
Net realized and unrealized mark-to-market and hedging transactions	(134)	443	216
Receivables	844	(249)	(231)
Inventory	(24)	(80)	(48)
Other current assets	1,276	(944)	(33)
Increase (decrease) in			
Accounts payable	(1,524)	117	(5)
Taxes accrued	(69)	53	188
Other current liabilities	(594)	622	91
Capital expenditures for residential real estate	(322)	(355)	(322)
Cost of residential real estate sold	143	294	268
Other, assets	1,005	193	(155)
Other, liabilities	194	533	158
Net cash provided by operating activities	3,748	2,818	4,168
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures	(3,381)	(2,327)	(2,161)
Investment expenditures	(89)	(43)	(46)
Acquisitions, net of cash acquired	(284)	(294)	—
Cash acquired from acquisition of Cinergy	147	—	—
Purchases of available-for-sale securities	(33,436)	(40,317)	(65,929)
Proceeds from sales and maturities of available-for-sale securities	32,596	40,131	65,098
Net proceeds from the sales of equity investments and other assets, and sales of and collections on notes receivable	2,861	2,375	1,619
Proceeds from the sales of commercial and multi-family real estate	254	372	606
Settlement of net investment hedges and other investing derivatives	(163)	(296)	—
Distributions from equity investments	152	383	—
Purchases of emission allowances	(228)	(18)	—
Sales of emission allowances	194	—	—
Other	49	(92)	20
Net cash used in investing activities	(1,328)	(126)	(793)
CASH FLOWS FROM FINANCING ACTIVITIES			
Proceeds from the:			
Issuance of long-term debt	2,369	543	153
Issuance of common stock and common stock related to employee benefit plans	127	41	1,704
Payments for the redemption of:			
Long-term debt	(2,098)	(1,346)	(3,646)
Preferred stock of a subsidiary	(12)	(134)	(176)
Decrease in cash overdrafts	(2)	—	—
Notes payable and commercial paper	(412)	165	(67)
Distributions to minority interests	(304)	(861)	(1,477)
Contributions from minority interests	247	779	1,277
Dividends paid	(1,488)	(1,105)	(1,065)
Repurchase of common shares	(500)	(933)	—
Proceeds from Duke Energy Income Fund	104	110	—
Other	8	24	19
Net cash used in financing activities	(1,961)	(2,717)	(3,278)

Changes in cash and cash equivalents included in assets held for sale	(22)	3	39
Net increase (decrease) in cash and cash equivalents	437	(22)	136
Cash and cash equivalents at beginning of period	511	533	397
Cash and cash equivalents at end of period	$ 948	$ 511	$ 533
Supplemental Disclosures			
Cash paid for interest, net of amount capitalized	$ 1,154	$ 1,089	$ 1,323
Cash paid (refunded) for income taxes	$ 460	$ 546	$ (339)
Acquisition of Cinergy Corp			
Fair value of assets acquired	$ 17,304	$ —	$ —
Liabilities assumed	$ 12,709	$ —	$ —
Issuance of common stock	$ 8,993	$ —	$ —
Significant non-cash transactions:			
Conversion of convertible notes to stock	$ 632	$ 28	$ —
AFUDC—equity component	$ 58	$ 30	$ 25
Transfer of DEFS Canadian Facilities	$ —	$ 97	$ —
Debt retired in connection with disposition of business	$ —	$ —	$ 840
Note receivable from sale of southeastern plants	$ —	$ —	$ 48
Remarketing of senior notes	$ —	$ —	$ 1,625

See Notes to Consolidated Financial Statements

Table of Contents

PART II

DUKE ENERGY CORPORATION
Consolidated Statements of Common Stockholders' Equity and Comprehensive Income
(In millions)

	Common Stock Shares	Common Stock	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss): Foreign Currency Adjustments	Accumulated Other Comprehensive Income (Loss): Net Gains (Losses) on Cash Flow Hedges	Accumulated Other Comprehensive Income (Loss): Minimum Pension Liability Adjustment	Accumulated Other Comprehensive Income (Loss): SFAS No 158 Adjustment	Other	Total
Balance December 31, 2003	**911**	**$ 9,513**		**$ 4,066**	**$ 315**	**$ 298**	**$ (444)**	**$ —**	**$ —**	**$ 13,748**
Net income	—	—	—	1,490	—	—	—	—	—	1,490
Other Comprehensive Income										
Foreign currency translation adjustments	—	—	—	—	279	—	—	—	—	279
Foreign currency translation adjustments reclassified into earnings as a result of the sale of Asia-Pacific Business	—	—	—	—	(54)	—	—	—	—	(54)
Net unrealized gains on cash flow hedges (b)	—	—	—	—	—	311	—	—	—	311
Reclassification into earnings from cash flow hedges (c)	—	—	—	—	—	(83)	—	—	—	(83)
Minimum pension liability adjustment (d)	—	—	—	—	—	—	28	—	—	28
Total comprehensive income										1,971
Dividend reinvestment and employee benefits	5	128	—	—	—	—	—	—	—	128
Equity offering	41	1,625	—	—	—	—	—	—	—	1,625
Common stock dividends	—	—	—	(1,018)	—	—	—	—	—	(1,018)
Preferred and preference stock dividends	—	—	—	(9)	—	—	—	—	—	(9)
Other capital stock transactions, net	—	—	—	(4)	—	—	—	—	—	(4)
Balance December 31, 2004	**957**	**$ 11,266**	**$ —**	**$ 4,525**	**$ 540**	**$ 526**	**$ (416)**	**$ —**	**$ —**	**$ 16,441**
Net income	—	—	—	1,824	—	—	—	—	—	1,824
Other Comprehensive Income										
Foreign currency translation adjustments (a)	—	—	—	—	306	—	—	—	—	306
Net unrealized gains on cash flow hedges (b)	—	—	—	—	—	413	—	—	—	413
Reclassification into earnings from cash flow hedges (c)	—	—	—	—	—	(1,026)	—	—	—	(1,026)
Minimum pension liability adjustment (d)	—	—	—	—	—	—	356	—	—	356
Other (f)								—	17	17
Total comprehensive income										1,890
Dividend reinvestment and employee benefits	3	85		—	—	—	—	—	—	85
Stock repurchase	(33)	(933)		—	—	—	—	—	—	(933)
Conversion of debt	1	28								28
Common stock dividends	—	—	—	(1,093)	—	—	—	—	—	(1,093)
Preferred and preference stock dividends	—	—	—	(12)	—	—	—	—	—	(12)

Other capital stock transactions, net	—	—	—	33	—	—	—	—	—	33
Balance December 31, 2005	**928**	**$ 10,446**	**$ —**	**$ 5,277**	**$ 846**	**$ (87)**	**$ (60)**	**$ —**	**$ 17**	**$ 16,439**
Net income	—	—	—	1,863	—	—	—	—	—	1,863
Other Comprehensive Income										
Foreign currency translation adjustments	—	—	—	—	103	—	—	—	—	103
Net unrealized gains on cash flow hedges (b)	—	—	—	—	—	6	—	—	—	6
Reclassification into earnings from cash flow hedges (c)	—	—	—	—	—	36	—	—	—	36
Minimum pension liability adjustment (d)	—	—	—	—	—	—	(1)	—	—	(1)
Other (f)	—	—	—	—	—	—	—	—	(15)	(15)
Total comprehensive income										1,992
Retirement of old Duke Energy shares	(927)	(10,399)	—	—	—	—	—	—	—	(10,399)
Issuance of new Duke Energy shares	927	1	10,398	—	—	—	—	—	—	10,399
Common stock issued in connection with Cinergy merger	313	—	8,993	—	—	—	—	—	—	8,993
Conversion of Cinergy options to Duke Energy options	—	—	59	—	—	—	—	—	—	59
Dividend reinvestment and employee benefits	6	22	172	—	—	—	—	—	—	194
Stock repurchase	(17)	(69)	(431)	—	—	—	—	—	—	(500)
Common stock dividends	—	—	—	(1,488)	—	—	—	—	—	(1,488)
Conversion of debt to equity	27	—	632	—	—	—	—	—	—	632
Tax benefit due to conversion of debt to equity	—	—	34	—	—	—	—	—	—	34
Adjustment due to SFAS No. 158 adoption (e)	—	—	—	—	—	—	61	(311)	—	(250)
Other capital stock transactions, net	—	—	(3)	—	—	—	—	—	—	(3)
Balance December 31, 2006	**1,257**	**$ 1**	**$ 19,854**	**$ 5,652**	**$ 949**	**$ (45)**	**$ —**	**$ (311)**	**$ 2**	**$ 26,102**

(a) Foreign currency translation adjustments, net of $62 tax benefit in 2005 The 2005 tax benefit related to the settled net investment hedges (see Note 8) Substantially all of the 2005 tax benefit is a correction of an immaterial accounting error related to prior periods

(b) Net unrealized gains on cash flow hedges, net of $3 tax expense in 2006, $233 tax expense in 2005, and $170 tax expense in 2004

(c) Reclassification into earnings from cash flow hedges, net of $19 tax expense in 2006, $583 tax benefit in 2005, and $45 tax benefit in 2004 Reclassification into earnings from cash flow hedges in 2006, is due primarily to the recognition of Duke Energy North America's (DENA) unrealized net gains related to hedges on forecasted transactions which will no longer occur as a result of the sale to LS Power of substantially all of DENA's assets and contracts outside of the Midwestern United States and certain contractual positions related to the Midwestern assets (see Notes 8 and 13)

(d) Minimum pension liability adjustment, net of $0 tax benefit in 2006, $228 tax expense in 2005, and $18 tax expense in 2004

(e) Adjustment due to SFAS No 158 adoption, net of $144 tax benefit in 2006 Excludes $595 recorded as a regulatory asset (see Note 22)

(f) Net of $9 tax benefit in 2006, and $10 tax expense in 2005

See Notes to Consolidated Financial Statements

PART II

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements
For the Years Ended December 31, 2006, 2005 and 2004

1. Summary of Significant Accounting Policies

Nature of Operations and Basis of Consolidation. Duke Energy Corporation (collectively with its subsidiaries, Duke Energy), is an energy company located in the Americas These Consolidated Financial Statements include, after eliminating intercompany transactions and balances, the accounts of Duke Energy and all majority-owned subsidiaries where Duke Energy has control, and those variable interest entities where Duke Energy is the primary beneficiary These Consolidated Financial Statements also reflect Duke Energy's proportionate share of certain generation and transmission facilities in North Carolina and the Midwest

Duke Energy Holding Corp (Duke Energy HC) was incorporated in Delaware on May 3, 2005 as Deer Holding Corp , a wholly-owned subsidiary of Duke Energy Corporation (Old Duke Energy). On April 3, 2006, in accordance with their previously announced merger agreement, Old Duke Energy and Cinergy Corp (Cinergy) merged into wholly-owned subsidiaries of Duke Energy HC, resulting in Duke Energy HC becoming the parent entity In connection with the closing of the merger transactions, Duke Energy HC changed its name to Duke Energy Corporation (New Duke Energy or Duke Energy) and Old Duke Energy converted into a limited liability company named Duke Power Company LLC (subsequently renamed Duke Energy Carolinas, LLC (Duke Energy Carolinas) effective October 1, 2006) As a result of the merger transactions, each outstanding share of Cinergy common stock was converted into 1 56 shares of ~~common stock of Duke Energy, which resulted in the issuance of approximately 313 million shares. Additionally, each share of common stock of Old Duke Energy was converted into one~~ share of Duke Energy common stock. Old Duke Energy is the predecessor of Duke Energy for purposes of U S securities regulations governing financial statement filing Therefore, the accompanying Consolidated Financial Statements reflect the results of operations of Old Duke Energy for the three months ended March 31, 2006 and the years ended December 31, 2005 and 2004 and the financial position of Old Duke Energy as of December 31, 2005 New Duke Energy had separate operations for the period beginning with the effective date of the Cinergy merger, and references to amounts for periods after the closing of the merger relate to New Duke Energy Cinergy's results have been included in the accompanying Consolidated Statements of Operations from the effective date of acquisition and thereafter (see "Cinergy Merger" in Note 2). Both Old Duke Energy and New Duke Energy are referred to as Duke Energy herein

Shares of common stock of New Duke Energy carry a stated par value of $0 001, while shares of common stock of Old Duke Energy had been issued at no par In April 2006, as a result of the conversion of all outstanding shares of Old Duke Energy common stock to New Duke Energy common stock, the par value of the shares issued was recorded in Common Stock within Common Stockholders' Equity in the Consolidated Balance Sheets and the excess of issuance price over stated par value was recorded in Additional Paid-in Capital within Common Stockholders' Equity in the Consolidated Balance Sheets Prior to the conversion of common stock from shares of Old Duke Energy to New Duke Energy, all proceeds from issuances of common stock were solely reflected in Common Stock within Common Stockholders' Equity in the Consolidated Balance Sheets.

On September 7, 2006, Duke Energy deconsolidated Crescent Resources, LLC (Crescent) due to a reduction in ownership and its inability to exercise control over Crescent (see Note 2) Crescent has been accounted for as an equity method investment since the date of deconsolidation

Effective July 1, 2005, Duke Energy has deconsolidated DCP Midstream, LLC (formerly Duke Energy Field Services, LLC) (DEFS) due to a reduction in ownership and its inability to exercise control over DEFS (see Note 2). DEFS has been subsequently accounted for as an equity method investment

On January 2, 2007, Duke Energy completed the spin-off of its natural gas businesses, including Duke Energy's 50% interest in DEFS, to shareholders The new natural gas business, which is named Spectra Energy Corp (Spectra Energy), consists principally of the operations of Spectra Energy Capital LLC (Spectra Energy Capital, formerly Duke Capital LLC), excluding certain operations which were transferred from Spectra Energy Capital to Duke Energy in December 2006, primarily International Energy and Duke Energy's effective 50% interest in the Crescent JV The use of the term Spectra Energy Capital relates to operations of the former Duke Capital LLC or the post-spin Spectra Energy Capital, as the context requires Amounts contained in these Notes, as well as the accompanying Consolidated Financial Statements, include assets and liabilities, results of operations and cash flows, as well as certain litigation matters and guarantee obligations, which have been transferred to Spectra Energy as part of the spin-off

Use of Estimates. To conform to generally accepted accounting principles (GAAP) in the United States, management makes estimates and assumptions that affect the amounts reported in the Consolidated Financial Statements and Notes Although these estimates are based on management's best available knowledge at the time, actual results could differ

DUKE ENERGY CORPORATION
Notes To Consolidated Financial Statements—(Continued)

Reclassifications and Revisions Certain prior period amounts have been reclassified within the Consolidated Statements of Cash Flows to conform to current year presentation

Cash and Cash Equivalents. All highly liquid investments with original maturities of three months or less at the date of acquisition are considered cash equivalents

Restricted Funds Held in Trust. At December 31, 2006, Duke Energy had approximately $212 million of restricted cash related primarily to proceeds from debt issuances that are held in trust, primarily for the purpose of funding future environmental expenditures. This amount is reflected in Other Investments and Other Assets on the Consolidated Balance Sheets.

Short-term Investments. Duke Energy actively invests a portion of its available cash balances in various financial instruments, such as tax-exempt debt securities that frequently have stated maturities of 20 years or more and tax-exempt money market preferred securities These instruments provide for a high degree of liquidity through features such as daily and seven day notice put options and 7, 28, and 35 day auctions which allow for the redemption of the investments at their face amounts plus earned income As Duke Energy intends to sell these instruments within one year or less, generally within 30 days from the balance sheet date, they are classified as current assets Duke Energy has classified all short-term investments that are debt securities as available-for-sale under Statement of Financial Accounting Standards (SFAS) No 115, "Accounting For Certain Investments in Debt and Equity Securities," (SFAS No 115), and they are carried at fair market value Investments in money-market preferred securities that do not have stated redemptions are accounted for at their cost, as the carrying values approximate market values due to their short-term maturities and no credit risk. Realized gains and losses and dividend and interest income related to these securities, including any amortization of discounts or premiums arising at acquisition, are included in earnings as incurred. Purchases and sales of available-for-sale securities are presented on a gross basis within Investing Cash Flows in the accompanying Consolidated Statements of Cash Flows.

Inventory. Inventory consists primarily of materials and supplies and natural gas held in storage for transmission, processing and sales commitments; and coal held for electric generation Inventory is recorded at the lower of cost or market value, primarily using the average cost method The increase in inventory at December 31, 2006 as compared to December 31, 2005 is primarily attributable to inventory acquired as part of the merger with Cinergy

Components of Inventory

	December 31,	
	2006	2005
	(in millions)	
Materials and supplies	$ 586	$ 434
Natural gas	290	269
Coal held for electric generation	383	115
Petroleum products	99	45
Total inventory	$ 1,358	$ 863

Accounting for Risk Management and Hedging Activities and Financial Instruments. Duke Energy uses a number of different derivative and non-derivative instruments in connection with its commodity price, interest rate and foreign currency risk management activities and its trading activities, including swaps, futures, forwards, options and swaptions All derivative instruments not designated and qualifying for the normal purchases and normal sales exception under SFAS No 133, "Accounting for Derivative Instruments and Hedging Activities" (SFAS No 133), as amended, are recorded on the Consolidated Balance Sheets at their fair value as Unrealized Gains or Unrealized Losses on Mark-to-Market and Hedging Transactions. Cash inflows and outflows related to derivative instruments, except those that contain financing elements and those related to net investment hedges and other investing activities, are a component of operating cash flows in the accompanying Consolidated Statements of Cash Flows Cash inflows and outflows related to derivative instruments containing financing elements are a component of financing cash flows in the accompanying Consolidated Statements of Cash Flows while cash inflows and outflows related to net investment hedges and derivatives related to other investing activities are a component of investing cash flows in the accompanying Consolidated Statements of Cash Flows.

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

Duke Energy designates all energy commodity derivatives as either trading or non-trading Gains and losses for all derivative contracts that do not represent physical delivery contracts are reported on a net basis in the Consolidated Statements of Operations For each of the Duke Energy's physical delivery contracts that are derivatives, the accounting model and presentation of gains and losses, or revenue and expense in the Consolidated Statements of Operations is shown below

Classification of Contract	Duke Energy Accounting Model	Presentation of Gains & Losses or Revenue & Expense
Trading derivatives	Mark-to-market(a)	Net basis in Non-regulated Electric, Natural Gas, Natural Gas Liquids (NGL), and Other
Non-trading derivatives:		
Cash flow hedge	Accrual(b)	Gross basis in the same income statement category as the related hedged item
Fair value hedge	Accrual(b)	Gross basis in the same income statement category as the related hedged item
Normal purchase or sale	Accrual(b)	Gross basis upon settlement in the corresponding income statement category based on commodity type
Undesignated	Mark-to-market(a)	Net basis in the related income statement category for interest rate, currency and commodity derivatives

(a) An accounting term used by Duke Energy to refer to derivative contracts for which an asset or liability is recognized at fair value and the change in the fair value of that asset or liability is recognized in the Consolidated Statements of Operations, with the exception of Union Gas Limited's (Union Gas) regulated business, which is recognized as a regulatory asset or liability This term is applied to trading and undesignated non-trading derivative contracts As this term is not explicitly defined within GAAP, Duke Energy's application of this term could differ from that of other companies

(b) An accounting term used by Duke Energy to refer to contracts for which there is generally no recognition in the Consolidated Statements of Operations for any changes in fair value until the service is provided, the associated delivery period occurs or there is hedge ineffectiveness As discussed further below, this term is applied to derivative contracts that are accounted for as cash flow hedges, fair value hedges, and normal purchases or sales, as well as to non-derivative contracts used for commodity risk management purposes As this term is not explicitly defined within GAAP, Duke Energy's application of this term could differ from that of other companies

Where Duke Energy's derivative instruments are subject to a master netting agreement and the criteria of the Financial Accounting Standards Board (FASB) Interpretation (FIN) No 39, "Offsetting of Amounts Related to Certain Contracts—An Interpretation of Accounting Principles Board (APB) Opinion No 10 and FASB Statement No 105" (FIN 39), are met, Duke Energy presents its derivative assets and liabilities, and accompanying receivables and payables, on a net basis in the accompanying Consolidated Balance Sheets

Cash Flow and Fair Value Hedges Qualifying energy commodity and other derivatives may be designated as either a hedge of a forecasted transaction or future cash flows (cash flow hedge) or a hedge of a recognized asset, liability or firm commitment (fair value hedge) For all hedge contracts, Duke Energy prepares formal documentation of the hedge in accordance with SFAS No 133 In addition, at inception and every three months, Duke Energy formally assesses whether the hedge contract is highly effective in offsetting changes in cash flows or fair values of hedged items Duke Energy documents hedging activity by transaction type (futures/swaps) and risk management strategy (commodity price risk/interest rate risk).

Changes in the fair value of a derivative designated and qualified as a cash flow hedge, to the extent effective, are included in the Consolidated Statements of Common Stockholders' Equity and Comprehensive Income (Loss) as Accumulated Other Comprehensive Income (Loss) (AOCI) until earnings are affected by the hedged transaction Duke Energy discontinues hedge accounting prospectively when it has determined that a derivative no longer qualifies as an effective hedge, or when it is no longer probable that the hedged forecasted transaction will occur When hedge accounting is discontinued because the derivative no longer qualifies as an effective hedge, the derivative is subject to the Mark-to-Market Model of Accounting (MTM Model) prospectively Gains and losses related to discontinued hedges that were previously accumulated in AOCI will remain in AOCI until the underlying contract is reflected in earnings; unless it is probable that the hedged forecasted transaction will not occur at which time associated deferred amounts in AOCI are immediately recognized in current earnings

For derivatives designated as fair value hedges, Duke Energy recognizes the gain or loss on the derivative instrument, as well as the offsetting loss or gain on the hedged item in earnings, to the extent effective, in the current period All derivatives designated and accounted for as hedges are classified in the same category as the item being hedged in the Consolidated Statements of Cash Flows In addition, all components of each derivative gain or loss are included in the assessment of hedge effectiveness

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

Normal Purchases and Normal Sales On a limited basis, Duke Energy Carolinas and Duke Energy Ohio apply the normal purchase and normal sales exception to certain contracts. If contracts cease to meet this exception, the fair value of the contracts is recognized on the Consolidated Balance Sheets and the contracts are accounted for using the MTM Model unless immediately designated as a cash flow or fair value hedge

As a result of the September 2005 decision to pursue the sale or other disposition of substantially all of Duke Energy North America's (DENA's) remaining physical and commercial assets outside the Midwestern United States, Duke Energy discontinued hedge accounting for forward natural gas and power contracts accounted for as cash flow hedges related to the former DENA operations and disqualified other forward power contracts previously designated under the normal purchases normal sales exception effective September 2005

Valuation. When available, quoted market prices or prices obtained through external sources are used to measure a contract's fair value For contracts with a delivery location or duration for which quoted market prices are not available, fair value is determined based on internally developed valuation techniques or models For derivatives recognized under the MTM Model, valuation adjustments are also recognized in the Consolidated Statements of Operations

Goodwill. Duke Energy evaluates goodwill for potential impairment under the guidance of SFAS No 142, "Goodwill and Other Intangible Assets" (SFAS No 142) Under this provision, goodwill is subject to an annual test for impairment. Duke Energy has designated August 31 as the date it performs the annual review for goodwill impairment for its reporting units Under the provisions of SFAS No 142, Duke Energy performs the annual review for goodwill impairment at the reporting unit level, which Duke Energy has determined to be an operating segment or one level below

Impairment testing of goodwill consists of a two-step process The first step involves a comparison of the implied fair value of a reporting unit with its carrying amount If the carrying amount of the reporting unit exceeds its fair value, the second step of the process involves a comparison of the fair value and carrying value of the goodwill of that reporting unit If the carrying value of the goodwill of a reporting unit exceeds the implied fair value of that goodwill, an impairment loss is recognized in an amount equal to the excess. Additional impairment tests are performed between the annual reviews if events or changes in circumstances make it more likely than not that the fair value of a reporting unit is below its carrying amount.

Duke Energy primarily uses a discounted cash flow analysis to determine fair value Key assumptions in the determination of fair value include the use of an appropriate discount rate, estimated future cash flows and an estimated run rates of operation, maintenance, and general and administrative costs In estimating cash flows, Duke Energy incorporates expected growth rates, regulatory stability and ability to renew contracts as well as other factors into its revenue and expense forecasts

Other Long-term Investments. Other long-term investments, primarily marketable securities held in the Nuclear Decommissioning Trust Funds (NDTF) and the captive insurance investment portfolio, are classified as available-for-sale securities as management does not have the intent or ability to hold the securities to maturity, nor are they bought and held principally for selling them in the near term The securities are reported at fair value on Duke Energy's Consolidated Balance Sheets Unrealized and realized gains and losses, net of tax, on the NDTF are reflected in regulatory assets or liabilities on Duke Energy's Consolidated Balance Sheets as Duke Energy expects to recover all costs for decommissioning its nuclear generation assets through regulated rates Unrealized holding gains and losses, net of tax, on all other available-for-sale securities are reflected in AOCI in Duke Energy's Consolidated Balance Sheets until they are realized, at which time they are reflected in earnings Cash flows from purchases and sales of long-term investments (including the NDTF) are presented on a gross basis within investing cash flows in the accompanying Consolidated Statements of Cash Flows

Property, Plant and Equipment. Property, plant and equipment are stated at the lower of historical cost less accumulated depreciation or fair value, if impaired Duke Energy capitalizes all construction-related direct labor and material costs, as well as indirect construction costs Indirect costs include general engineering, taxes and the cost of funds used during construction The cost of renewals and betterments that extend the useful life of property, plant and equipment is also capitalized The cost of repairs, replacements and major maintenance projects, which do not extend the useful life or increase the expected output of property, plant and equipment, is expensed as it is incurred Depreciation is generally computed over the asset's estimated useful life using the straight-line method. The composite weighted-average depreciation rates, excluding nuclear fuel, were 3 51% for 2006, 3 34% for 2005, and 3 49% for 2004 Also, see "Deferred Returns and Allowance for Funds Used During Construction (AFUDC)," discussed below

When Duke Energy retires its regulated property, plant and equipment, it charges the original cost plus the cost of retirement, less salvage value, to accumulated depreciation and amortization When it sells entire regulated operating units, or retires or sells

DUKE ENERGY CORPORATION
Notes To Consolidated Financial Statements—(Continued)

non-regulated properties, the cost is removed from the property account and the related accumulated depreciation and amortization accounts are reduced. Any gain or loss is recorded in earnings, unless otherwise required by the applicable regulatory body

Duke Energy recognizes asset retirement obligations (ARO's) in accordance with SFAS No 143, "Accounting For Asset Retirement Obligations" (SFAS No. 143), for legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or normal use of the asset and FIN No. 47, "Accounting for Conditional Asset Retirement Obligations" (FIN 47), for conditional ARO's in which the timing or method of settlement are conditional on a future event that may or may not be within the control of Duke Energy. Both SFAS No 143 and FIN 47 require that the fair value of a liability for an ARO be recognized in the period in which it is incurred, if a reasonable estimate of fair value can be made. The fair value of the liability is added to the carrying amount of the associated asset. This additional carrying amount is then depreciated over the estimated useful life of the asset

Investments in Residential, Commercial, and Multi-Family Real Estate. Prior to the deconsolidation of Crescent in September 2006, investments in residential, commercial and multi-family real estate were carried at cost, net of any related depreciation, except for any properties meeting the criteria in SFAS No 144, "Accounting for the Impairment or Disposal of Long-lived Assets" (SFAS No 144), to be presented as Assets Held for Sale, which are carried at lower of cost or fair value less costs to sell in the Consolidated Balance Sheets. Proceeds from sales of residential properties are presented within Operating Revenues and the cost of properties sold are included in Operation, Maintenance and Other in the Consolidated Statements of Operations. Cash flows related to the acquisition, development and disposal of residential properties are included in Cash Flows from Operating Activities in the Consolidated Statements of Cash Flows. Gains and losses on sales of commercial and multi-family properties as well as "legacy" land sales are presented as such in the Consolidated Statements of Operations, and cash flows related to these activities are included in Cash Flows from Investing Activities in the Consolidated Statements of Cash Flows

Long-Lived Asset Impairments, Assets Held For Sale and Discontinued Operations. Duke Energy evaluates whether long-lived assets, excluding goodwill, have been impaired when circumstances indicate the carrying value of those assets may not be recoverable. For such long-lived assets, an impairment exists when its carrying value exceeds the sum of estimates of the undiscounted cash flows expected to result from the use and eventual disposition of the asset. When alternative courses of action to recover the carrying amount of a long-lived asset are under consideration, a probability-weighted approach is used for developing estimates of future undiscounted cash flows. If the carrying value of the long-lived asset is not recoverable based on these estimated future undiscounted cash flows, the impairment loss is measured as the excess of the asset's carrying value over its fair value, such that the asset's carrying value is adjusted to its estimated fair value

Management assesses the fair value of long-lived assets using commonly accepted techniques, and may use more than one source. Sources to determine fair value include, but are not limited to, recent third party comparable sales, internally developed discounted cash flow analysis and analysis from outside advisors. Significant changes in market conditions resulting from events such as changes in commodity prices or the condition of an asset, or a change in management's intent to utilize the asset would generally require management to re-assess the cash flows related to the long-lived assets

Duke Energy uses the criteria in SFAS No 144 to determine when an asset is classified as "held for sale." Upon classification as "held for sale," the long-lived asset or asset group is measured at the lower of its carrying amount or fair value less cost to sell, depreciation is ceased and the asset or asset group is separately presented on the Consolidated Balance Sheets. When an asset or asset group meets the SFAS No 144 criteria for classification as held for sale within the Consolidated Balance Sheets, Duke Energy does not retrospectively adjust prior period balance sheets to conform to current year presentation

Duke Energy uses the criteria in SFAS No 144 and EITF 03-13, "Applying the Conditions in Paragraph 42 of FASB Statement No. 144 in Determining Whether to Report Discontinued Operations" (EITF 03-13), to determine whether components of Duke Energy that are being disposed of or are classified as held for sale are required to be reported as discontinued operations in the Consolidated Statements of Operations. To qualify as a discontinued operation under SFAS No 144, the component being disposed of must have clearly distinguishable operations and cash flows. Additionally, pursuant to EITF 03-13, Duke Energy must not have significant continuing involvement in the operations after the disposal (i e Duke Energy must not have the ability to influence the operating or financial policies of the disposed component) and cash flows of the operations being disposed of must have been eliminated from Duke Energy's ongoing operations (i e Duke Energy does not expect to generate significant direct cash flows from activities involving the disposed component after the disposal transaction is completed). Assuming both preceding conditions are met, the related results of operations for the current and prior periods, including any related impairments, are reflected as (Loss) Income From Discontinued Operations, net of tax, in the Consolidated Statements of Operations. If an asset held for sale does not meet the requirements for discontinued operations classification,

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

any impairments and gains or losses on sales are recorded in continuing operations as Gains (Losses) on Sales of Other Assets and Other, net, in the Consolidated Statements of Operations Impairments for all other long-lived assets, excluding goodwill, are recorded as Impairment and Other Charges in the Consolidated Statements of Operations

Captive Insurance Reserves. Duke Energy has captive insurance subsidiaries which provide insurance coverage to Duke Energy entities as well as certain third parties, on a limited basis, for various business risks and losses, such as workers compensation, property, business interruption and general liability Liabilities include provisions for estimated losses incurred, but not yet reported (IBNR), as well as provisions for known claims which have been estimated on a claims-incurred basis IBNR reserve estimates involve the use of assumptions and are primarily based upon historical loss experience, industry data and other actuarial assumptions Reserve estimates are adjusted in future periods as actual losses differ from historical experience Intercompany balances and transactions are eliminated in consolidation

Duke Energy's captive insurance entities also have reinsurance coverage, which provides reimbursement to Duke Energy for certain losses above a per incident and/or aggregate retention Duke Energy's captive insurance entities also have an aggregate stop-loss insurance coverage, which provides reimbursement from third parties to Duke Energy for its paid losses above certain per line of coverage aggregate amounts during a policy year Duke Energy recognizes a reinsurance receivable for recovery of incurred losses under its captive's reinsurance and stop-loss insurance coverage once realization of the receivable is deemed probable by its captive insurance companies

During 2004, Duke Energy eliminated intercompany reserves at its captive insurance subsidiaries of approximately $64 million which was a correction of an immaterial accounting error related to prior periods

Unamortized Debt Premium, Discount and Expense. Premiums, discounts and expenses incurred with the issuance of outstanding long-term debt are amortized over the terms of the debt issues Any call premiums or unamortized expenses associated with refinancing higher-cost debt obligations to finance regulated assets and operations are amortized consistent with regulatory treatment of those items, where appropriate

Environmental Expenditures. Duke Energy expenses environmental expenditures related to conditions caused by past operations that do not generate current or future revenues Environmental expenditures related to operations that generate current or future revenues are expensed or capitalized, as appropriate Liabilities are recorded when the necessity for environmental remediation becomes probable and the costs can be reasonably estimated, or when other potential environmental liabilities are reasonably estimable and probable

Cost-Based Regulation. Duke Energy accounts for certain of its regulated operations under the provisions of SFAS No 71, "Accounting for Certain Types of Regulation" (SFAS No 71) The economic effects of regulation can result in a regulated company recording assets for costs that have been or are expected to be approved for recovery from customers or recording liabilities for amounts that are expected to be returned to customers in the rate-setting process in a period different from the period in which the amounts would be recorded by an unregulated enterprise Accordingly, Duke Energy records assets and liabilities that result from the regulated ratemaking process that would not be recorded under GAAP for non-regulated entities Management continually assesses whether regulatory assets are probable of future recovery by considering factors such as applicable regulatory changes, recent rate orders applicable to other regulated entities and the status of any pending or potential deregulation legislation Based on this continual assessment, management believes the existing regulatory assets are probable of recovery These regulatory assets and liabilities are primarily classified in the Consolidated Balance Sheets as Regulatory Assets and Deferred Debits, and Deferred Credits and Other Liabilities Duke Energy periodically evaluates the applicability of SFAS No 71, and considers factors such as regulatory changes and the impact of competition If cost-based regulation ends or competition increases, Duke Energy may have to reduce its asset balances to reflect a market basis less than cost and write-off their associated regulatory assets and liabilities (For further information see Note 4)

Guarantees. Duke Energy accounts for guarantees and related contracts, for which it is the guarantor, under FIN No 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others" (FIN 45) In accordance with FIN 45, upon issuance or modification of a guarantee on or after January 1, 2003, Duke Energy recognizes a liability at the time of issuance or material modification for the estimated fair value of the obligation it assumes under that guarantee, if any Fair value is estimated using a probability-weighted approach Duke Energy reduces the obligation over the term of the guarantee or related contract in a systematic and rational method as risk is reduced under the obligation. Any additional contingent loss for guarantee contracts outside the scope of FIN 45 is accounted for and recognized in accordance with SFAS No 5, "Accounting for Contingencies" (SFAS No 5)

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

Duke Energy has entered into various indemnification agreements related to purchase and sale agreements and other types of contractual agreements with vendors and other third parties. These agreements typically cover environmental, tax, litigation and other matters, as well as breaches of representations, warranties and covenants Typically, claims may be made by third parties for various periods of time, depending on the nature of the claim Duke Energy's potential exposure under these indemnification agreements can range from a specified to an unlimited dollar amount, depending on the nature of the claim and the particular transaction (see Note 18).

Stock-Based Compensation. Effective January 1, 2006, Duke Energy adopted the provisions of SFAS No 123(R), "Share-Based Payment" (SFAS No 123(R)) (see Note 20) SFAS No 123(R) establishes accounting for stock-based awards exchanged for employee and certain non-employee services Accordingly, for employee awards, equity classified stock-based compensation cost is measured at the grant date, based on the fair value of the award, and is recognized as expense over the requisite service period, which generally begins on the date the award is granted through the earlier of the date the award vests or the date the employee becomes retirement eligible Awards, including stock options, granted to employees that are already retirement eligible are deemed to have vested immediately upon issuance, and therefore, compensation cost for those awards is recognized on the date such awards are granted.

Duke Energy elected to adopt the modified prospective application method as provided by SFAS No 123(R), and accordingly, financial statement amounts periods prior to January 1, 2006 in this Form 10-K have not been restated There were no modifications to outstanding stock options prior to the adoption of SFAS 123(R)

Duke Energy previously applied Accounting Principles Board (APB) Opinion No. 25, "Accounting for Stock Issued to Employees," and FIN 44, "Accounting for Certain Transactions Involving Stock Compensation (an Interpretation of APB Opinion 25)" and provided the required pro forma disclosures of SFAS No 123, "Accounting for Stock-Based Compensation" (SFAS No 123) Since the exercise price for all stock options granted under those plans was equal to the market value of the underlying common stock on the grant date, no compensation cost was recognized in the accompanying Consolidated Statements of Operations

Revenue Recognition. Revenues on sales of electricity, primarily at U S Franchised Electric and Gas, are recognized when the service is provided Unbilled revenues are estimated by applying an average revenue/kilowatt hour for all customer classes to the number of estimated kilowatt hours delivered, but not billed Differences between actual and estimated unbilled revenues are immaterial

Revenues on sales of natural gas, natural gas transportation, storage and distribution as well as sales of petroleum products, primarily at Natural Gas Transmission and Field Services (prior to deconsolidation on July 1, 2005), are recognized when either the service is provided or the product is delivered Revenues related to these services provided or products delivered, but not yet billed, are estimated each month These estimates are generally based on contract data, regulatory information, estimated distribution usage based on historical data adjusted for heating degree days, commodity prices and preliminary throughput and allocation measurements Final bills for the current month are billed and collected in the following month Differences between actual and estimated unbilled revenues are immaterial

Crescent sells residential developed lots in North Carolina, South Carolina, Georgia, Florida, Texas and Arizona Crescent recognizes revenues from the sale of residential developed lots at closing Prior to the deconsolidation of Crescent in September 2006, profit was recognized under the full accrual method using estimates of average gross profit per lot within a project or phase of a project based on total estimated project costs Land and land development costs were allocated to land sold based on relative sales values Crescent recognized revenues from commercial and multi-family project sales at closing, or later using a deferral method when the criteria for sale accounting had not been met at closing Profit was recognized based on the difference between the sales price and the carrying cost of the project Revenue was recognized under the completed contract method for condominium units that Crescent developed and sold in Florida

Nuclear Fuel. Amortization of nuclear fuel purchases is included in the Consolidated Statements of Operations as Fuel Used in Electric Generation and Purchased Power The amortization is recorded using the units-of-production method

Deferred Returns and Allowance for Funds Used During Construction (AFUDC). Deferred returns, recorded in accordance with SFAS No 71, represent the estimated financing costs associated with funding certain regulatory assets or liabilities of U S Franchised Electric and Gas Those costs arise primarily from the funding of purchased capacity costs collected in rates Deferred returns are non-cash items and are primarily recognized as an addition to purchased capacity costs, which are included in Other Current Liabilities and Other Deferred Credits and Other Liabilities on the Consolidated Balance Sheets, with an offsetting debit or credit to Other Income and Expenses, net The amount of deferred returns included in Other Income and Expenses, net was ($15) million in 2006, ($13) million in 2005, and ($9) million in 2004

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

AFUDC, which represents the estimated debt and equity costs of capital funds necessary to finance the construction of new regulated facilities, consists of two components, an equity component and an interest component The equity component is a non-cash item AFUDC is capitalized as a component of Property, Plant and Equipment cost, with offsetting credits to the Consolidated Statements of Operations After construction is completed, Duke Energy is permitted to recover these costs through inclusion in the rate base and in the depreciation provision The total amount of AFUDC included in the Consolidated Statements of Operations was $97 million in 2006, which consisted of an after-tax equity component of $58 million and a before-tax interest expense component of $39 million The total amount of AFUDC included in the Consolidated Statements of Operations was $48 million in 2005, which consisted of an after-tax equity component of $30 million and a before-tax interest expense component of $18 million The total amount of AFUDC included in the Consolidated Statements of Operations was $39 million in 2004, which consisted of an after-tax equity component of $25 million and a before-tax interest expense component of $14 million

Accounting For Sales of Stock by a Subsidiary. Duke Energy accounts for sales of stock by a subsidiary under Staff Accounting Bulletin (SAB) No 51, "Accounting for Sales of Stock of a Subsidiary" (SAB 51) Under SAB 51, companies may elect, via an accounting policy decision, to record a gain on the sale of stock of a subsidiary equal to the amount of proceeds received in excess of the carrying value of the shares Duke Energy has elected to treat such excesses as gains in earnings, which are reflected in Gain on Sale of Subsidiary Stock in the Consolidated Statements of Operations During the year ended December 31, 2006, Duke Energy recognized a gain of approximately $15 million related to the sale of securities of the Duke Energy Income Fund (Income Fund) (see Note 11).

Accounting For Purchases and Sales of Emission Allowances. Duke Energy recognizes emission allowances in earnings as they are consumed or sold Gains or losses on sales of emission allowances for non-regulated businesses are presented on a net basis in Gains (Losses) on Sales of Other Assets and Other, net, in the accompanying Consolidated Statements of Operations For regulated businesses that do provide for direct recovery of emission allowances, any gains or losses on sales of recoverable emission allowances are included in the rate structure of the regulated entity and are deferred as a regulatory asset or liability Future rates charged to retail customers are impacted by any gain or loss on sales of recoverable emission allowances and, therefore, as the recovery of the gain or loss is recognized in operating revenues, the regulatory asset or liability related to the emission allowance activity is recognized as a component of Fuel Used in Electric Generation and Purchased Power in the Consolidated Statements of Operations For regulated businesses that do not provide for direct recovery of emission allowances through a cost tracking mechanism, gains and losses on sales of emission allowances are included in Gains (Losses) on Sales of Other Assets and Other, net in the Consolidated Statements of Operations, or are deferred, depending on level of regulatory certainty Purchases and sales of emission allowances are presented gross as investing activities on the Consolidated Statements of Cash Flows

Income Taxes. Duke Energy and its subsidiaries file a consolidated federal income tax return and other state and foreign jurisdictional returns as required Deferred income taxes have been provided for temporary differences between the GAAP and tax carrying amounts of assets and liabilities These differences create taxable or tax-deductible amounts for future periods Investment tax credits have been deferred and are being amortized over the estimated useful lives of the related properties

Management evaluates and records contingent tax liabilities and related interest based on the probability of ultimately sustaining the tax deductions or income positions Management assesses the probabilities of successfully defending the tax deductions or income positions based upon statutory, judicial or administrative authority

Excise Taxes. Certain excise taxes levied by state or local governments are collected by Duke Energy from its customers These taxes, which are required to be paid regardless of Duke Energy's ability to collect from the customer, are accounted for on a gross basis When Duke Energy acts as an agent, and the tax is not required to be remitted if it is not collected from the customer, the taxes are accounted for on a net basis Duke Energy's excise taxes accounted for on a gross basis and recorded as revenues in the accompanying Consolidated Statements of Operations for years ended December 31, 2006, 2005, and 2004 were as follows:

	Year Ended December 31, 2006	Year Ended December 31, 2005	Year Ended December 31, 2004
		(in millions)	
Excise Taxes	$ 221	$ 121	$ 116

Segment Reporting. SFAS No 131, "Disclosures about Segments of an Enterprise and Related Information" (SFAS No 131), establishes standards for a public company to report financial and descriptive information about its reportable operating segments in annual and interim financial reports Operating segments are components of an enterprise about which separate financial information is available and evaluated regularly by the chief operating decision maker in deciding how to allocate resources and evaluate performance

Two or more operating segments may be aggregated into a single reportable segment provided aggregation is consistent with the objective and basic principles of SFAS No 131, if the segments have similar economic characteristics, and the segments are considered similar under criteria provided by SFAS No 131 There is no aggregation within Duke Energy's defined business segments SFAS No 131 also establishes standards and related disclosures about the way the operating segments were determined, products and services, geographic areas and major customers, differences between the measurements used in reporting segment information and those used in the general-purpose financial statements, and changes in the measurement of segment amounts from period to period The description of Duke Energy's reportable segments, consistent with how business results are reported internally to management and the disclosure of segment information in accordance with SFAS No 131, are presented in Note 3

Foreign Currency Translation. The local currencies of Duke Energy's foreign operations have been determined to be their functional currencies, except for certain foreign operations whose functional currency has been determined to be the U S Dollar, based on an assessment of the economic circumstances of the foreign operation, in accordance with SFAS No 52, "Foreign Currency Translation " Assets and liabilities of foreign operations, except for those whose functional currency is the U S Dollar, are translated into U S Dollars at current exchange rates Translation adjustments resulting from fluctuations in exchange rates are included as a separate component of AOCI Revenue and expense accounts of these operations are translated at average exchange rates prevailing during the year Gains and losses arising from transactions denominated in currencies other than the functional currency, which were not material for all periods presented, are included in the results of operations of the period in which they occur. Deferred taxes are not provided on translation gains and losses where Duke Energy expects earnings of a foreign operation to be permanently reinvested Gains and losses relating to derivatives designated as hedges of the foreign currency exposure of a net investment in foreign operations are reported in foreign currency translation as a separate component of AOCI

Statements of Consolidated Cash Flows Duke Energy has made certain classification elections within its Consolidated Statements of Cash Flows related to discontinued operations, cash received from insurance proceeds and cash overdrafts Cash flows from discontinued operations are combined with cash flows from continuing operations within operating, investing and financing cash flows within the Consolidated Statements of Cash Flows Cash received from insurance proceeds are classified depending on the activity that resulted in the insurance proceeds (for example, business interruption insurance proceeds are included as a component of operating activities while insurance proceeds from damaged property are included as a component of investing activities) With respect to cash overdrafts, book overdrafts are included within operating cash flows while bank overdrafts are included within financing cash flows

Distributions from Equity Investees. Duke Energy considers dividends received from equity investees which do not exceed cumulative equity in earnings subsequent to the date of investment a return on investment and classifies these amounts as operating activities within the accompanying Consolidated Statements of Cash Flows. Cumulative dividends received in excess of cumulative equity in earnings subsequent to the date of investment are considered a return of investment and are classified as investing activities within the accompanying Consolidated Statements of Cash Flows

Cumulative Effect of Changes in Accounting Principles. As of December 31, 2005, Duke Energy adopted the provisions of FIN 47 In accordance with the transition guidance of this standard, Duke Energy recorded a net-of-tax cumulative effect adjustment of approximately $4 million The cumulative effect adjustment had an immaterial impact on EPS

New Accounting Standards. The following new accounting standards were adopted by Duke Energy during the year ended December 31, 2006 and the impact of such adoption, if applicable, has been presented in the accompanying Consolidated Financial Statements:

SFAS No. 123(R) "Share-Based Payment" (SFAS No. 123(R)) In December 2004, the Financial Accounting Standards Board (FASB) issued SFAS No 123(R), which replaces SFAS No 123, "Accounting for Stock-Based Compensation," and supersedes APB Opinion No. 25, "Accounting for Stock Issued to Employees " SFAS No 123(R) requires all share-based payments to employees, including grants of employee stock options, to be recognized in the financial statements based on their fair values For Duke Energy, timing for implementation of SFAS No 123(R) was January 1, 2006 The pro forma disclosures previously permitted under SFAS No 123 are no longer an acceptable alternative Instead, Duke Energy is required to determine an appropriate expense for stock options and record compensation expense in the Consolidated Statements of Operations for stock options Duke Energy implemented SFAS No 123(R) using the modified prospective transition method, which required Duke Energy to record compensation expense for all unvested awards beginning January 1, 2006

Table of Contents

PART II

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

Duke Energy currently also has retirement eligible employees with outstanding share-based payment awards (unvested stock awards, stock based performance awards and phantom stock awards) Compensation cost related to those awards was previously expensed over the stated vesting period or until actual retirement occurred Effective January 1, 2006, Duke Energy is required to recognize compensation cost for new awards granted to employees over the requisite service period, which generally begins on the date the award is granted through the earlier of the date the award vests or the date the employee becomes retirement eligible Awards, including stock options, granted to employees that are already retirement eligible are deemed to have vested immediately upon issuance, and therefore, compensation cost for those awards is recognized on the date such awards are granted

The adoption of SFAS No 123(R) did not have a material impact on Duke Energy's consolidated results of operations, cash flows or financial position in 2006 based on awards outstanding as of the implementation date However, the impact to Duke Energy in periods subsequent to adoption of SFAS No. 123(R) will be largely dependent upon the nature of any new share-based compensation awards issued to employees (See Note 20)

Staff Accounting Bulletin (SAB) No. 107, "Share-Based Payment" (SAB No. 107). On March 29, 2005, the Securities and Exchange Commission (SEC) staff issued SAB No 107 to express the views of the staff regarding the interaction between SFAS No 123(R) and certain SEC rules and regulations and to provide the staff's views regarding the valuation of share-based payment arrangements for public companies Duke Energy adopted SFAS No 123(R) and SAB No 107 effective January 1, 2006

FASB Staff Position (FSP) No. FAS 123(R)-4, "Classification of Options and Similar Instruments Issued as Employee Compensation That Allow for Cash Settlement upon the Occurrence of a Contingent Event" (FSP No. FAS 123(R)-4) In February 2006, the FASB staff issued FSP FAS No. 123(R)-4 to address the classification of options and similar instruments issued as employee compensation that allow for cash settlement upon the occurrence of a contingent event The guidance amends SFAS No 123(R) FSP No. FAS 123(R)-4 provides that cash settlement features that can be exercised only upon the occurrence of a contingent event that is outside the employee's control does not require classifying the option or similar instrument as a liability until it becomes probable that the event will occur FSP No FAS 123(R)-4 applies only to options or similar instruments issued as part of employee compensation arrangements The guidance in FSP No FAS 123(R)-4 was effective for Duke Energy as of April 1, 2006 Duke Energy adopted SFAS No 123(R) as of January 1, 2006 (see Note 20) The adoption of FSP No. FAS 123(R)-4 did not have a material impact on Duke Energy's consolidated statement of operations, cash flows or financial position

FSP No. FAS 115-1 and 124-1. "The Meaning of Other-Than-Temporary Impairment and its Application to Certain Investments" (FSP No. FAS 115-1 and 124-1). The FASB issued FSP No. FAS 115-1 and 124-1 in November 2005, which was effective for Duke Energy beginning January 1, 2006 This FSP addresses the determination as to when an investment is considered impaired, whether that impairment is other than temporary, and the measurement of an impairment loss This FSP also includes accounting considerations subsequent to the recognition of an other-than-temporary impairment and requires certain disclosures about unrealized losses that have not been recognized as other-than-temporary impairments The guidance in this FSP amends SFAS No. 115, "Accounting for Certain Investments in Debt and Equity Securities," and SFAS No 124, "Accounting for Certain Investments Held by Not-for-Profit Organizations," and APB Opinion No. 18. The adoption of FSP No FAS 115-1 and 124-1 did not have a material impact on Duke Energy's consolidated results of operations, cash flows or financial position

FSP No. FIN 46(R)-6, "Determining the Variability to Be Considered In Applying FASB Interpretation No. 46(R) (FSP No FIN 46(R)-6) " In April 2006, the FASB staff issued FSP No. FIN 46(R)-6 to address how to determine the variability to be considered in applying FIN 46(R), "Consolidation of Variable Interest Entities " The variability that is considered in applying FIN 46(R) affects the determination of whether the entity is a variable interest entity (VIE), which interests are variable interests in the entity, and which party, if any, is the primary beneficiary of the VIE The variability affects the calculation of expected losses and expected residual returns This guidance is effective for all entities with which Duke Energy first becomes involved or existing entities for which a reconsideration event occurs after July 1, 2006 The adoption of FSP No FIN 46(R)-6 did not have a material impact on Duke Energy's consolidated results of operations, cash flows or financial position

EITF Issue No. 05-1, "Accounting for the Conversion of an Instrument that Becomes Convertible Upon the Issuer's Exercise of a Call Option" (EITF No. 05-1). In June 2006, the EITF reached a consensus on EITF No 05-1 The consensus requires that the issuance of equity securities to settle a debt instrument (pursuant to the instrument's original conversion terms) that became convertible upon the issuer's exercise of a call option be accounted for as a conversion if the debt instrument contained a substantive conversion feature as of its issuance date If the debt instrument did not contain a substantive conversion option as of its issuance date, the issuance of equity securities to settle the debt instrument should be accounted for as a debt extinguishment. The consensus was effective for Duke Energy for all conversions within its scope that resulted from the exercise of call options beginning July 1, 2006. The adoption of EITF No. 05-1 did not have a material impact on Duke Energy's consolidated results of operations, cash flows or financial position.

SFAS No. 158, "Employer's Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R)" (SFAS No. 158). In October 2006, the FASB issued SFAS No. 158, which changes the recognition and disclosure provisions and measurement date requirements for an employer's accounting for defined benefit pension and other postretirement plans. The recognition and disclosure provisions require an employer to (1) recognize the funded status of a benefit plan—measured as the difference between plan assets at fair value and the benefit obligation—in its statement of financial position, (2) recognize as a component of OCI, net of tax, the gains or losses and prior service costs or credits that arise during the period but are not recognized as components of net periodic benefit cost, and (3) disclose in the notes to financial statements certain additional information. SFAS No. 158 does not change the amounts recognized in the income statement as net periodic benefit cost. Duke Energy is required to initially recognize the funded status of its defined benefit pension and other postretirement plans and to provide the required additional disclosures as of December 31, 2006 (see Note 22). Retrospective application is not permitted. The adoption of SFAS No. 158 recognition and disclosure provisions resulted in an increase in total assets of approximately $211 million (consisting of an increase in regulatory assets of $595 million, an increase in deferred tax assets of $144 million, offset by a decrease in pre-funded pension costs of $522 million and a decrease in intangible assets of $6 million), an increase in total liabilities of approximately $461 million and a decrease in accumulated other comprehensive income, net of tax, of approximately $250 million as of December 31, 2006. The adoption of SFAS No. 158 did not have any material impact on Duke Energy's consolidated results of operations or cash flows.

Under the measurement date requirements of SFAS No. 158, an employer is required to measure defined benefit plan assets and obligations as of the date of the employer's fiscal year-end statement of financial position (with limited exceptions). Historically, Duke Energy has measured its plan assets and obligations up to three months prior to the fiscal year-end, as allowed under the authoritative accounting literature. The measurement date requirement is effective for the year ending December 31, 2008, and early application is encouraged. Duke Energy intends to adopt the change in measurement date effective January 1, 2007 by remeasuring plan assets and benefit obligations as of that date, pursuant to the transition requirements of SFAS No. 158. Net periodic benefit cost for the three-month period between September 30, 2006 and December 31, 2006 will be recognized, net of tax, as a separate adjustment of retained earnings as of January 1, 2007. Additionally, changes in plan assets and plan obligations between September 30, 2006 and December 31, 2006 not related to net periodic benefit cost will be recognized, net of tax, as an adjustment to OCI.

SAB No. 108, "Considering the Effects of Prior Year Misstatements When Quantifying Misstatements in Current Year Financial Statements" (SAB No. 108). In September 2006 the SEC issued SAB No. 108, which provides interpretive guidance on how the effects of the carryover or reversal of prior year misstatements should be considered in quantifying a current year misstatement. Traditionally, there have been two widely-recognized approaches for quantifying the effects of financial statement misstatements. The income statement approach focuses primarily on the impact of a misstatement on the income statement—including the reversing effect of prior year misstatements—but its use can lead to the accumulation of misstatements in the balance sheet. The balance sheet approach, on the other hand, focuses primarily on the effect of correcting the period-end balance sheet with less emphasis on the reversing effects of prior year errors on the income statement. The SEC staff believes that registrants should quantify errors using both a balance sheet and an income statement approach (a "dual approach") and evaluate whether either approach results in quantifying a misstatement that, when all relevant quantitative and qualitative factors are considered, is material.

SAB No. 108 was effective for Duke Energy's year ending December 31, 2006. SAB No. 108 permits existing public companies to initially apply its provisions either by (i) restating prior financial statements as if the "dual approach" had always been used or (ii), under certain circumstances, recording the cumulative effect of initially applying the "dual approach" as adjustments to the carrying values of assets and liabilities as of January 1, 2006 with an offsetting adjustment recorded to the opening balance of retained earnings. Duke Energy has historically used a dual approach for quantifying identified financial statement misstatements. Therefore, the adoption of SAB No. 108 did not have any material impact on Duke Energy's consolidated results of operations, cash flows or financial position.

The following new accounting standards were adopted by Duke Energy during the year ended December 31, 2005 and the impact of such adoption, if applicable, has been presented in the accompanying Consolidated Financial Statements:

SFAS No. 153, "Exchanges of Nonmonetary Assets—an amendment of APB Opinion No. 29" (SFAS No. 153). In December 2004, the FASB issued SFAS No. 153 which amends APB Opinion No. 29, "Accounting for Nonmonetary Transactions," by eliminating the exception to the fair-value principle for exchanges of similar productive assets, which were accounted for under APB Opinion No 29 based on the book value of the asset surrendered with no gain or loss recognition SFAS No 153 also eliminates APB Opinion No 29's concept of culmination of an earnings process The amendment requires that an exchange of nonmonetary assets be accounted for at fair value if the exchange has commercial substance and fair value is determinable within reasonable limits Commercial substance is assessed by comparing the entity's expected cash flows immediately before and after the exchange If the difference is significant, the transaction is considered to have commercial substance and should be recognized at fair value SFAS No 153 is effective for nonmonetary transactions occurring on or after July 1, 2005 The adoption of SFAS No 153 did not have a material impact on Duke Energy's consolidated results of operations, cash flows or financial position

FASB Interpretation No. (FIN) 47 "Accounting for Conditional Asset Retirement Obligations" (FIN 47). In March 2005, the FASB issued FIN 47, which clarifies the accounting for conditional asset retirement obligations as used in SFAS No 143, "Accounting for Asset Retirement Obligations," (SFAS No 143). A conditional asset retirement obligation is an unconditional legal obligation to perform an asset retirement activity in which the timing and (or) method of settlement are conditional on a future event that may or may not be within the control of the entity Therefore, an entity is required to recognize a liability for the fair value of a conditional asset retirement obligation under SFAS No 143 if the fair value of the liability can be reasonably estimated The provisions of FIN 47 were effective for Duke Energy as of December 31, 2005, and resulted in an increase in assets of $31 million, an increase in liabilities of $35 million and a net-of-tax cumulative effect adjustment to earnings of approximately $4 million.

FASB Staff Position (FSP) No. APB 18-1, "Accounting by an Investor for Its Proportionate Share of Accumulated Other Comprehensive Income of an Investee Accounted for under the Equity Method in Accordance with APB Opinion No. 18 upon a Loss of Significant Influence" (FSP No. APB 18-1) In July 2005, the FASB staff issued FSP No APB 18-1 which provides guidance for how an investor should account for its proportionate share of an investee's equity adjustments for other comprehensive income (OCI) upon a loss of significant influence APB Opinion No 18, "The Equity Method of Accounting for Investments in Common Stock" (APB Opinion No 18), requires a transaction of an equity method investee of a capital nature be accounted for as if the investee were a consolidated subsidiary, which requires the investor to record its proportionate share of the investee's adjustments for OCI as increases or decreases to the investment account with corresponding adjustments in equity FSP No APB 18-1 requires that an investor's proportionate share of an investee's equity adjustments for OCI should be offset against the carrying value of the investment at the time significant influence is lost and equity method accounting is no longer appropriate However, to the extent that the offset results in a carrying value of the investment that is less than zero, an investor should (a) reduce the carrying value of the investment to zero and (b) record the remaining balance in income The guidance in FSP No APB 18-1 was effective for Duke Energy beginning October 1, 2005 The adoption of FSP No APB 18-1 did not have a material impact on Duke Energy's consolidated results of operations, cash flows or financial position.

The following new accounting standards were adopted by Duke Energy during the year ended December 31, 2004 and the impact of such adoption, if applicable, has been presented in the accompanying Consolidated Financial Statements:

FIN 46, "Consolidation of Variable Interest Entities". In January 2003, the FASB issued FIN 46 which requires the primary beneficiary of a variable interest entity's activities to consolidate the variable interest entity FIN 46 defines a variable interest entity as an entity in which the equity investors do not have substantive voting rights and there is not sufficient equity at risk for the entity to finance its activities without additional subordinated financial support The primary beneficiary absorbs a majority of the expected losses and/or receives a majority of the expected residual returns of the variable interest entity's activities. In December 2003, the FASB issued FIN 46 (Revised December 2003), "Consolidation of Variable Interest Entities—An Interpretation of ARB No 51" (FIN 46R), which supersedes and amends the provisions of FIN 46 While FIN 46R retains many of the concepts and provisions of FIN 46, it also provides additional guidance and additional scope exceptions, and incorporates FASB Staff Positions related to the application of FIN 46.

The provisions of FIN 46 applied immediately to variable interest entities created, or interests in variable interest entities obtained, after January 31, 2003, while the provisions of FIN 46R were required to be applied to those entities, except for special purpose entities, by the end of the first reporting period ending after March 15, 2004 (March 31, 2004 for Duke Energy) For variable interest entities created, or interests in variable interest entities obtained, on or before January 31, 2003, FIN 46 or FIN 46R was required to be applied to special-purpose entities by the end of the first reporting period ending after December 15, 2003 (December 31, 2003 for Duke Energy), and was required to be applied to all other non-special purpose entities by the end of the first reporting period ending after March 15, 2004 (March 31, 2004 for Duke Energy)

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

See Note 23 for a discussion of certain variable interest entities acquired by Duke Energy as part of the Cinergy merger Duke Energy has consolidated certain non-special purpose operating entities, previously accounted for under the equity method of accounting These entities, which are substantive entities, had an immaterial amount of total assets as of December 31, 2006 and 2005 The impact of consolidating these entities on Duke Energy's consolidated financial statements was not material In addition, at December 31, 2005, Duke Energy recorded Net Property, Plant and Equipment of $109 million and Long-term Debt of $173 million on the Consolidated Balance Sheets, associated with a natural gas processing variable interest entity that was consolidated by Duke Energy In 2006, Duke Energy exercised its right to repurchase the assets held by the variable interest entity and repaid the loan

Various changes and clarifications to the provisions of FIN 46 have been made by the FASB since its original issuance in January 2003 While not anticipated at this time, any additional clarifying guidance or further changes to these complex rules could have an impact on Duke Energy's Consolidated Financial Statements

SFAS No. 132 (Revised 2003), "Employers' Disclosures about Pensions and Other Postretirement Benefits" (SFAS No. 132R). In December 2003, the FASB revised the provisions of SFAS No 132, "Employers' Disclosures about Pensions and Other Postretirement Benefits—an amendment of FASB Statements No 87, 88, and 106," to include additional disclosures related to defined-benefit pension plans and other defined-benefit post-retirement plans, such as the following:

- The long-term rate of return on plan assets, along with a narrative discussion on the basis for selecting the rate of return used
- Information about plan assets for each major asset category (i.e. equity securities, debt securities, real estate, etc.) along with the targeted allocation percentage of plan assets for each category and the actual allocation percentages at the measurement date
- The amount of benefit payments expected to be paid in each of the next five years and the following five-year period in the aggregate
- The current best estimate of the range of contributions expected to be made in the following year
- The accumulated benefit obligation for defined-benefit pension plans
- Disclosure of the measurement date utilized

Additionally, interim reports require additional disclosures related to the components of net periodic pension costs and the amounts paid or expected to be paid to the plan in the current fiscal year, if materially different than amounts previously disclosed The provisions of SFAS No 132R do not change the measurement or recognition provisions of defined-benefit pension and post-retirement plans as required by previous accounting standards The provisions of SFAS No 132R were applied by Duke Energy effective December 31, 2003 with the interim period disclosures applied beginning with the quarter ended March 31, 2004, except for the disclosure provisions of estimated future benefit payments which were effective for Duke Energy for the year ended December 31, 2004 (See Note 22 for the additional related disclosures)

FSP No. FAS 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003" (FSP No. FAS 106-2). In May 2004, the FASB staff issued FSP No FAS 106-2, which superseded FSP FAS 106-1, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003 " FSP No FAS 106-2 provides accounting guidance for the effects of the Medicare Prescription Drug Improvement and Modernization Act of 2003 (the Modernization Act) The Modernization Act introduced a prescription drug benefit under Medicare, as well as a federal subsidy to sponsors of retiree health care benefit plans that include prescription drug benefits FSP No FAS 106-2 requires a sponsor to determine if its prescription drug benefits are actuarially equivalent to the drug benefit provided under Medicare Part D as of the date of enactment of the Modernization Act, and if it is therefore entitled to receive the subsidy If a sponsor determines that its prescription drug benefits are actuarially equivalent to the Medicare Part D benefit, the sponsor should recognize the expected subsidy in the measurement of the accumulated postretirement benefit obligation (APBO) under SFAS No 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions " Any resulting reduction in the APBO is to be accounted for as an actuarial experience gain The subsidy's reduction, if any, of the sponsor's share of future costs under its prescription drug plan is to be reflected in current-period service cost

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

The provisions of FSP No. FAS 106-2 were effective for the first interim period beginning after June 15, 2004 Duke Energy adopted FSP No. FAS 106-2 retroactively to the date of enactment of the Modernization Act, December 8, 2003, as allowed by the FSP (See Note 22 for discussion of the effects of adopting this FSP)

FSP No. FAS 109-1, "Application of FASB Statement No. 109, Accounting for Income Taxes,' to the Tax Deduction on Qualified Production Activities Provided by the American Jobs Creation Act of 2004" (FSP No. FAS 109-1) On October 22, 2004, the President signed the American Jobs Creation Act of 2004 (the Act) The Act provides a deduction for income from qualified domestic production activities, which will be phased in from 2005 through 2010

Under the guidance in FSP No FAS 109-1, which was issued in December 2004, the deduction will be treated as a "special deduction" as described in SFAS No 109, "Accounting for Income Taxes" (SFAS No. 109) As such, for Duke Energy, the special deduction had no material impact on deferred tax assets and liabilities existing at the enactment date Rather, the impact of this deduction is reported in the periods in which the deductions are claimed on the tax returns For the years ended December 31, 2006 and 2005, Duke Energy recognized a benefit of approximately $0 and $9 million, respectively, relating to the deduction from qualified domestic activities

FSP No. FAS 109-2, "Accounting and Disclosure Guidance for the Foreign Earnings Repatriation Provision within the American Jobs Creation Act of 2004" (FSP No. FAS 109-2) In addition to the qualified domestic production activities deduction discussed above, the Act creates a temporary incentive for U S corporations to repatriate accumulated income earned abroad by providing an 85 percent dividends received deduction for certain dividends from controlled foreign corporations. FSP No. FAS 109-2, which was issued in December 2004, states that a company is allowed time beyond the financial reporting period of enactment to evaluate the effect of the Act on its plan for reinvestment or repatriation of foreign earnings, as it applies to the application of SFAS No. 109 Although the deduction is subject to a number of limitations and some uncertainty remains as to how to interpret numerous provisions in the Act, Duke Energy believes that it has the information necessary to make an informed decision on the impact of the Act on its repatriation plans Based on that decision, Duke Energy has repatriated approximately $500 million in extraordinary dividends, as defined in the Act, and accordingly recorded a corresponding tax liability of $39 million as of December 31, 2005 However, Duke Energy has not provided for U S deferred income taxes or foreign withholding tax on basis differences for its non-U S subsidiaries that result primarily from undistributed earnings of approximately $420 million as of December 31, 2006 and $290 million as of December 31, 2005, which Duke Energy intends to reinvest indefinitely Determination of the deferred tax liability on these basis differences is not practicable because such liability, if any, is dependent on circumstances existing if and when remittance occurs

EITF Issue No. 04-08, "The Effect of Contingently Convertible Debt on Diluted Earnings per Share" (EITF 04-08). In September 2004, the EITF reached a consensus on Issue No. 04-8 The consensus requires that the potential common stock related to contingently convertible securities (Co-Cos) with market price contingencies be included in diluted earnings per share calculations using the if-converted method specified in SFAS No 128, "Earnings per Share" (SFAS No 128), whether the market price contingencies have been met or not Co-Cos generally require conversion into a company's common stock if certain specified events occur, such as a specified market price for the company's common stock Prior to the issuance of EITF 04-08, Co-Cos were treated as contingently issuable shares under SFAS No. 128, and therefore, the contingencies, must have been met in order for the potential common shares to be included in diluted EPS Therefore, Co-Cos were only included in diluted EPS during periods in which the contingencies had been met The consensus is effective for fiscal years ended after December 15, 2004 and is required to be applied retroactively to all periods in which any Co-Cos were outstanding, resulting in restatement of diluted EPS if the impact of the Co-Cos was dilutive.

As discussed in Note 15, Duke Energy issued $770 million par value of contingently convertible notes in May of 2003, bearing an interest rate of 1 75% per annum that contain several contingencies, including a market price contingency that, if met, may require conversion of the notes into Duke Energy common stock Conversion may be required, at the option of the holder, if any one of the contingencies is met During 2006 and 2005, these convertible senior notes became convertible into shares of Duke Energy common stock due to the market price of Duke Energy common stock Holders of the convertible senior notes were allowed to exercise their right to convert on or prior to December 31, 2006 During 2006 and 2005, approximately 27 million and 1 2 million shares of common stock, respectively, were issued related to this conversion, which resulted in the retirement of approximately $632 million and $28 million of convertible senior notes, respectively Therefore, as discussed in Note 19, Duke Energy has included potential weighted average common shares outstanding of approximately 14 million, 32 million and 33 million for the years ended December 31, 2006, 2005 and 2004, respectively, in the calculation of diluted EPS

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

The following new accounting standards have been issued, but have not yet been adopted by Duke Energy as of December 31, 2006:

SFAS No. 155, "Accounting for Certain Hybrid Financial Instruments—an amendment of FASB Statements No. 133 and 140" (SFAS No. 155). In February 2006, the FASB issued SFAS No. 155, which amends SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" and SFAS No. 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities." SFAS No. 155 allows financial instruments that have embedded derivatives to be accounted for at fair value at acquisition, at issuance, or when a previously recognized financial instrument is subject to a remeasurement (new basis) event, on an instrument-by-instrument basis, in cases in which a derivative would otherwise have to be bifurcated. SFAS No. 155 is effective for Duke Energy for all financial instruments acquired, issued, or subject to remeasurement after January 1, 2007, and for certain hybrid financial instruments that have been bifurcated prior to the effective date, for which the effect is to be reported as a cumulative-effect adjustment to beginning retained earnings. Duke Energy does not anticipate the adoption of SFAS No. 155 will have any material impact on its consolidated results of operations, cash flows or financial position.

SFAS No. 156, "Accounting for Servicing of Financial Assets—an amendment of FASB Statement No. 140" (SFAS No. 156). In March 2006, the FASB issued SFAS No. 156, which amends SFAS No. 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities." SFAS No. 156 requires recognition of a servicing asset or liability when an entity enters into arrangements to service financial instruments in certain situations. Such servicing assets or servicing liabilities are required to be initially measured at fair value, if practicable. SFAS No. 156 also allows an entity to subsequently measure its servicing assets or servicing liabilities using either an amortization method or a fair value method. SFAS No. 156 is effective for Duke Energy as of January 1, 2007, and must be applied prospectively, except that where an entity elects to remeasure separately recognized existing arrangements and reclassify certain available-for-sale securities to trading securities, any effects must be reported as a cumulative-effect adjustment to retained earnings. Duke Energy does not anticipate the adoption of SFAS No. 156 will have any material impact on its consolidated results of operations, cash flows or financial position.

SFAS No. 157, "Fair Value Measurements" (SFAS No. 157). In September 2006, the FASB issued SFAS No. 157, which defines fair value, establishes a framework for measuring fair value in GAAP, and expands disclosures about fair value measurements. SFAS No. 157 does not require any new fair value measurements. However, in some cases, the application of SFAS No. 157 may change Duke Energy's current practice for measuring and disclosing fair values under other accounting pronouncements that require or permit fair value measurements. For Duke Energy, SFAS No. 157 is effective as of January 1, 2008 and must be applied prospectively except in certain cases. Duke Energy is currently evaluating the impact of adopting SFAS No. 157, and cannot currently estimate the impact of SFAS No. 157 on its consolidated results of operations, cash flows or financial position.

SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities" (SFAS No. 159). In February 2007, the FASB issued SFAS No. 159, which permits entities to choose to measure many financial instruments and certain other items at fair value. For Duke Energy, SFAS No. 159 is effective as of January 1, 2008 and will have no impact on amounts presented for periods prior to the effective date. Duke Energy cannot currently estimate the impact of SFAS No. 159 on its consolidated results of operations, cash flows or financial position and has not yet determined whether or not it will choose to measure items subject to SFAS No. 159 at fair value.

FIN 48, "Accounting for Uncertainty in Income Taxes—an interpretation of FASB Statement No. 109". In July 2006, the FASB issued FIN 48, which provides guidance on accounting for income tax positions about which Duke Energy has concluded there is a level of uncertainty with respect to the recognition in Duke Energy's financial statements. FIN 48 prescribes a minimum recognition threshold a tax position is required to meet. Tax positions are defined very broadly and include not only tax deductions and credits but also decisions not to file in a particular jurisdiction, as well as the taxability of transactions. Duke Energy will implement FIN 48 effective January 1, 2007. The implementation is expected to result in a cumulative effect adjustment to beginning Retained Earnings on the Consolidated Statement of Common Stockholders' Equity and Comprehensive Income (Loss) in the first quarter 2007 in the range of $15 million to $30 million. Corresponding entries will impact a variety of balance sheet line items, including Deferred income taxes, Taxes accrued, Other Liabilities, and Goodwill. Upon implementation of FIN 48, Duke Energy will reflect interest expense related to taxes as Interest Expense, in the Consolidated Statement of Operations. In addition, subsequent accounting for FIN 48 (after January 1, 2007) will involve an evaluation to determine if any changes have occurred that would impact the existing uncertain tax positions as well as determining whether any new tax positions are uncertain. Any impacts resulting from the evaluation of existing uncertain tax positions or from the recognition of new uncertain tax positions would impact income tax expense and interest expense in the Consolidated Statement of Operations, with offsetting impacts to the balance sheet line items described above. Because of the spin-off of Spectra Energy in the first quarter of 2007, certain liabilities and deferred tax assets related to uncertain tax positions filed on Spectra Energy tax returns will be removed from Duke Energy's balance sheet Uncertain tax positions on consolidated or combined tax returns filed by Duke Energy which are indemnified by Spectra Energy will be recorded as receivables from Spectra Energy

FSP No. FAS 123(R)-5, "Amendment of FASB Staff Position FAS 123(R)-1" (FSP No. FAS 123(R)-5) In October 2006, the FASB staff issued FSP No FAS 123(R)-5 to address whether a modification of an instrument in connection with an equity restructuring should be considered a modification for purposes of applying FSP No FAS 123(R)-1, "Classification and Measurement of Freestanding Financial Instruments Originally Issued in Exchange for Employee Services under FASB Statement No 123(R) (FSP No FAS 123(R)-1)." In August 2005, the FASB staff issued FSP FAS 123(R)-1 to defer indefinitely the effective date of paragraphs A230–A232 of SFAS No 123(R), and thereby require entities to apply the recognition and measurement provisions of SFAS No 123(R) throughout the life of an instrument, unless the instrument is modified when the holder is no longer an employee The recognition and measurement of an instrument that is modified when the holder is no longer an employee should be determined by other applicable generally accepted accounting principles. FSP No FAS 123(R)-5 addresses modifications of stock-based awards made in connection with an equity restructuring and clarifies that for instruments that were originally issued as employee compensation and then modified, and that modification is made to the terms of the instrument solely to reflect an equity restructuring that occurs when the holders are no longer employees, no change in the recognition or the measurement (due to a change in classification) of those instruments will result if certain conditions are met. This FSP is effective for Duke Energy as of January 1, 2007. The impact to Duke Energy of applying FSP No. FAS 123(R)-5 in subsequent periods will be dependent upon the nature of any modifications to Duke Energy's share-based compensation awards

FSP No. AUG AIR-1, "Accounting for Planned Major Maintenance Activities," (FSP No. AUG AIR-1) In September 2006, the FASB Staff issued FSP No AUG AIR-1 This FSP prohibits the use of the accrue-in-advance method of accounting for planned major maintenance activities in annual and interim financial reporting periods, if no liability is required to be recorded for an asset retirement obligation based on a legal obligation for which the event obligating the entity has occurred. The FSP also requires disclosures regarding the method of accounting for planned major maintenance activities and the effects of implementing the FSP The guidance in this FSP is effective for Duke Energy as of January 1, 2007 and will be applied retrospectively for all financial statements presented Duke Energy does not anticipate the adoption of FSP No AUG AIR-1 will have any material impact on its consolidated results of operations, cash flows or financial position.

EITF Issue No. 06-3, "How Taxes Collected from Customers and Remitted to Governmental Authorities Should Be Presented in the Income Statement (That Is, Gross versus Net Presentation)" (EITF No. 06-3) In June 2006, the EITF reached a consensus on EITF No 06-3 to address any tax assessed by a governmental authority that is directly imposed on a revenue-producing transaction between a seller and a customer and may include, but are not limited to, sales, use, value added, and some excise taxes For taxes within the issue's scope, the consensus requires that entities present such taxes on either a gross (i e included in revenues and costs) or net (i e exclude from revenues) basis according to their accounting policies, which should be disclosed If such taxes are reported gross and are significant, entities should disclose the amounts of those taxes Disclosures may be made on an aggregate basis The consensus is effective for Duke Energy beginning January 1, 2007 Duke Energy does not anticipate the adoption of EITF No 06-3 will have any material impact on its consolidated results of operations, cash flows or financial position

EITF Issue No. 06-5, "Accounting for Purchases of Life Insurance—Determining the Amount That Could Be Realized in Accordance with FASB Technical Bulletin No. 85-4" (EITF No. 06-5) In June 2006, the EITF reached a consensus on the accounting for corporate-owned and bank-owned life insurance policies. EITF No 06-5 requires that a policyholder consider the cash surrender value and any additional amounts to be received under the contractual terms of the policy in determining the amount that could be realized under the insurance contract. Amounts that are recoverable by the policyholder at the discretion of the insurance company must be excluded from the amount that could be realized Fixed amounts that are recoverable by the policyholder in future periods in excess of one year from the surrender of the policy must be recognized at their present value. EITF No 06-5 is effective for Duke Energy as of January 1, 2007 and must be applied as a change in accounting principle through a cumulative-effect adjustment to retained earnings or other components of equity as of January 1, 2007 Duke Energy does not anticipate the adoption of EITF No 06-5 will have any material impact on its consolidated results of operations, cash flows or financial position

EITF Issue No. 06-6, "Debtor's Accounting for a Modification (or Exchange) of Convertible Debt Instruments" (EITF No. 06-6) In November 2006, the EITF reached a consensus on EITF No 06-6 EITF No 06-6 addresses how a modification of a debt instrument (or an exchange of debt instruments) that affects the terms of an embedded conversion option should be considered in the issuer's analysis of whether debt extinguishment accounting should be applied, and further addresses the accounting for a modification of a debt instrument (or an exchange of debt instruments) that affects the terms of an embedded conversion option when extinguishment accounting is

DUKE ENERGY CORPORATION
Notes To Consolidated Financial Statements—(Continued)

not applied EITF No 06-6 applies to modifications (or exchanges) occurring in interim or annual reporting periods beginning after November 29, 2006, regardless of when the instrument was originally issued Early application is permitted for modifications (or exchanges) occurring in periods for which financial statements have not been issued. There were no modifications to, or exchanges of, any of Duke Energy's debt instruments within the scope of EITF No 06-6 in 2006 The impact to Duke Energy of applying EITF No 06-6 in subsequent periods will be dependent upon the nature of any modifications to, or exchanges of, any debt instruments within the scope of EITF No 06-6 Refer to Note 15

2. Acquisitions and Dispositions

Acquisitions. Duke Energy consolidates assets and liabilities from acquisitions as of the purchase date, and includes earnings from acquisitions in consolidated earnings after the purchase date Assets acquired and liabilities assumed are recorded at estimated fair values on the date of acquisition The purchase price minus the estimated fair value of the acquired assets and liabilities meeting the definition of a business as defined in EITF Issue No 98-3, "Determining Whether a Nonmonetary Transaction Involves Receipt of Productive Assets or of a Business" (EITF 98-3), is recorded as goodwill The allocation of the purchase price may be adjusted if additional, requested information is received during the allocation period, which generally does not exceed one year from the consummation date, however, it may be longer for certain income tax items

Cinergy Merger. On April 3, 2006, the previously announced merger between Duke Energy and Cinergy was consummated (see Note 1 for additional information) For accounting purposes, the effective date of the merger was April 1, 2006 The merger combines the Duke Energy and Cinergy regulated franchises as well as deregulated generation in the Midwestern United States The merger provides more regulatory, geographic and weather diversity to Duke Energy's earnings See Note 4 for discussion of regulatory impacts of the merger

The merger has been accounted for under the purchase method of accounting with Duke Energy treated as the acquirer for accounting purposes. As a result, the assets and liabilities of Cinergy were recorded at their respective fair values as of April 3, 2006 and the results of Cinergy's operations are included in the Duke Energy consolidated financial statements beginning as of the effective date of the merger Except for an adjustment related to pension and other postretirement benefit obligations, as mandated by SFAS No 87, "Employers' Accounting for Pensions" (SFAS No 87) and SFAS No 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions," (SFAS No 106), the accompanying consolidated financial statements do not reflect any pro forma adjustments related to Cinergy's regulated operations that are accounted for pursuant to SFAS No. 71, which are comprised of the regulated transmission and distribution operations of Duke Energy Ohio, Inc (Duke Energy Ohio) (formerly The Cincinnati Gas & Electric Company's regulated transmission and distribution), Duke Energy Indiana, Inc (Duke Energy Indiana) (formerly PSI Energy, Inc) and Duke Energy Kentucky, Inc (Duke Energy Kentucky) (formerly The Union Light, Heat and Power Company). Under the rate setting and recovery provisions currently in place for these regulated operations which provide revenues derived from cost, the fair values of the individual tangible and intangible assets and liabilities are considered to approximate their carrying values

The fair values used for recording the assets acquired and liabilities assumed are based on valuation analyses

In connection with the merger, Duke Energy issued 1 56 shares of Duke Energy common stock for each outstanding share of Cinergy common stock, which resulted in the issuance of approximately 313 million shares of Duke Energy common stock. Based on the market price of Duke Energy common stock during the period including the two trading days before through the two trading days after May 9, 2005, the date Duke Energy and Cinergy announced the merger, the transaction is valued at approximately $9 1 billion and has resulted in incremental goodwill to Duke Energy of approximately $4 5 billion The amount of goodwill results from significant strategic and financial benefits of the merger including:

- increased financial strength and flexibility;
- stronger utility business platform;
- greater scale and fuel diversity, as well as improved operational efficiencies for the merchant generation business;
- broadened electric distribution platform;
- improved reliability and customer service through the sharing of best practices;
- increased scale and scope of the electric and gas businesses with stand-alone strength;
- complementary positions in the Midwest;

- greater customer diversity;
- combined expertise; and
- significant cost savings synergies.

The following table summarizes the estimated fair values of the assets acquired and liabilities assumed at the date of acquisition:

Purchase Price Allocation

	April 3, 2006
	(in millions)
Purchase price	$ 9,115
Current assets	2,670
Investments and other assets	1,499
Property, plant and equipment[(a)]	10,595
Intangible assets	1,091
Regulatory assets and deferred debits	1,449
Total assets acquired	17,304
Current liabilities	4,137
Long-term debt	4,295
Deferred credits and other liabilities	4,266
Minority interests	11
Net identifiable assets acquired	4,595
Goodwill	$ 4,520

(a) Amounts recorded for regulated property, plant and equipment by Duke Energy on the acquisition date are net of approximately $3,995 million of accumulated depreciation of acquired assets.

Goodwill recorded as of December 31, 2006 resulting from Duke Energy's merger with Cinergy is $4,385 million, none of which is deductible for income tax purposes. Approximately $135 million of goodwill was allocated to Cinergy Marketing and Trading, LP, and Cinergy Canada, Inc. (collectively CMT) (see Note 13), which was sold in October 2006. As of December 31, 2006, the allocation of the remaining goodwill to the reporting units was substantially complete, with approximately $3,500 million and $885 million being allocated to the U.S. Franchised Electric and Gas and Commercial Power segments, respectively (see Note 10).

The following unaudited consolidated pro forma financial results are presented as if the Cinergy merger had occurred at the beginning of each of the periods presented:

Unaudited Consolidated Pro Forma Results

	Year Ended December 31,	
	2006	2005
	(in millions, except per share amounts)	
Operating revenues	$ 16,776	$ 21,413
Income from continuing operations	2,009	2,897
Net income	1,854	2,230
Earnings available for common stockholders	1,854	2,218
Earnings per share (from continuing operations)		
Basic	$ 1.61	$ 2.32
Diluted	$ 1.58	$ 2.26
Earnings per share		
Basic	$ 1.48	$ 1.78
Diluted	$ 1.46	$ 1.73

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

Pro forma results for the year ended December 31, 2006 include approximately $128 million of charges related to costs to achieve the merger and related synergies, which are recorded within Operating Expenses on the Consolidated Statements of Operations. Pro forma results for the years ended December 31, 2006 and 2005 do not reflect the pro forma effects of any significant transactions completed by Duke Energy other than the merger with Cinergy. The pre-tax impacts of purchase accounting on the 2006 results of operations of Duke Energy were charges of approximately $98 million.

Other Acquisitions. During the first quarter of 2006, International Energy closed on two transactions which resulted in the acquisition of an additional 27% interest in the Aguaytia Integrated Energy Project (Aguaytia), located in Peru, for approximately $31 million (approximately $18 million net of cash acquired). The project's scope includes the production and processing of natural gas, sale of liquefied petroleum gas (LPG) and NGLs and the generation, transmission and sale of electricity from a 177 megawatt power plant. These acquisitions increased International Energy's ownership in Aguaytia to 66% and resulted in Duke Energy accounting for Aguaytia as a consolidated entity. Prior to the acquisition of this additional interest, Aguaytia was accounted for as an equity method investment. No goodwill was recorded as a result of this acquisition.

During the first quarter of 2006, Duke Energy acquired the remaining 33 1/3% interest in Bridgeport Energy LLC (Bridgeport) from United Bridgeport Energy LLC (UBE) for approximately $71 million. No goodwill was recorded as a result of this acquisition. The assets and liabilities of Bridgeport were included as part of DENA's power generation assets which were sold to a subsidiary of LS Power Equity Partners (LS Power) (see Note 13).

In May 2006, Duke Energy announced an agreement to acquire an 825 megawatt power plant located in Rockingham County, North Carolina, from Dynegy for approximately $195 million. The Rockingham plant is a peaking power plant used during times of high electricity demand, generally in the winter and summer months and consists of five 165 megawatt combustion turbine units capable of using either natural gas or oil to operate. The acquisition is consistent with Duke Energy's plan to meet customers' electric needs for the foreseeable future. The transaction, which closed in the fourth quarter of 2006, required approvals by the North Carolina Utilities Commission (NCUC) and the Federal Energy Regulatory Commission (FERC). The NCUC approved it on July 25, 2006 and the FERC issued an order authorizing the transaction on October 31, 2006. In addition, the U.S. Federal Trade Commission (FTC) approved the transaction on July 20, 2006, under the Hart-Scott-Rodino Antitrust Improvement Act. No goodwill was recorded as a result of this acquisition.

In August 2005, Natural Gas Transmission acquired natural gas storage and pipeline assets in Southwest Virginia and an additional 50% interest in Saltville Gas Storage LLC (Saltville Storage) from units of AGL Resources for approximately $62 million. This transaction increased Natural Gas Transmission's ownership percentage of Saltville Storage to 100%. No goodwill was recorded as a result of this acquisition.

In August 2005, Natural Gas Transmission acquired the Empress System natural gas processing and NGL marketing business from ConocoPhillips for approximately $230 million as part of the Field Services ConocoPhillips transaction discussed further in the Dispositions section below. No goodwill was recorded as a result of this acquisition.

In the second quarter of 2004, Field Services acquired gathering, processing and transmission assets in southeast New Mexico from ConocoPhillips for a total purchase price of approximately $80 million, consisting of $74 million in cash and the assumption of approximately $6 million of liabilities. As the acquired assets were not considered businesses under the guidance in EITF 98-3, no goodwill was recognized in connection with this transaction.

In the third quarter of 2004, Field Services acquired additional interest in three separate entities (for which DEFS owned less than 100%, but had been consolidating) for a total purchase price of $4 million, and the exchange of some Field Services' assets. Two of these acquisitions, Mobile Bay Processing Partners (MBPP) and Gulf Coast NGL Pipeline, LLC (GC), resulted in 100% ownership by Field Services. The MBPP transaction involved MBPP transferring certain long-lived assets to El Paso Corporation for El Paso Corporation's interest in MBPP. As a result of this non-monetary transaction, the assets transferred were written-down to their estimated fair value which resulted in Duke Energy recognizing a pre-tax impairment of approximately $13 million, which was approximately $4 million net of minority interest. An additional 12% interest in Dauphin Island Gathering Partners (DIGP) was also purchased for $2 million, which resulted in 84% ownership by Field Services. MBPP owns processing assets in the Onshore Gulf of Mexico. GC owns a 16.67% interest in two equity investments. DIGP owns gathering and transmission assets in the Offshore Gulf of Mexico.

The pro forma results of operations for Duke Energy as if those acquisitions (other than the Cinergy merger) which closed prior to December 31, 2006 occurred as of the beginning of the periods presented do not materially differ from reported results.

PART II

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

Dispositions. In December 2006, Duke Energy Indiana agreed to sell one unit of its Wabash River Power Station (Unit 1) to the Wabash Valley Power Association The price of the transaction will be based on the book value of Unit 1 at the time of closing, which is currently estimated to be approximately $110-$120 million The sale must be approved by the Indiana Utility Regulatory Commission (IURC), the FERC, the FTC and the Department of Justice (DOJ) These approvals are anticipated by mid-2007 Duke Energy does not anticipate recognizing a material gain or loss on this transaction

On January 12, 2007, Duke Energy Indiana filed a petition with the IURC requesting authority to sell Wabash River Unit #1 to the Wabash Valley Power Association, Inc pursuant to an Asset Purchase Agreement along with approval of the Operation and Maintenance Agreement and the Common Facilities Agreement associated with the sale Wabash River Unit #1 will be replaced by the Wheatland facility which was purchased by Duke Energy Indiana in 2005 Duke Energy Indiana is also requesting approval of the accounting and ratemaking treatment of the sale to reflect the difference in costs of the two facilities

For the year ended December 31, 2006, the sale of other assets and businesses resulted in approximately $2 billion in proceeds and net pre-tax gains of $276 million recorded in Gains (Losses) on Sales of Other Assets and Other, net on the Consolidated Statements of Operations These sales exclude assets that were held for sale and reflected in discontinued operations, both of which are discussed in Note 13, and sales by Crescent prior to deconsolidation which are discussed separately below Significant sales of other assets during 2006 are detailed as follows:

- On September 7, 2006, an indirect wholly owned subsidiary of Duke Energy closed an agreement to create a joint venture of Crescent (the Crescent JV) with Morgan Stanley Real Estate Fund V U S , L P (MSREF) and other affiliated funds controlled by Morgan Stanley (collectively the "MS Members"). Under the agreement, the Duke Energy subsidiary contributed all of the membership interests in Crescent to a newly-formed joint venture, which was ascribed an enterprise value of approximately $2 1 billion as of December 31, 2005 In conjunction with the formation of the Crescent JV, the joint venture, Crescent and Crescent's subsidiaries entered into a credit agreement with third party lenders under which Crescent borrowed approximately $1 21 billion, net of transaction costs, of which approximately $1 19 billion was immediately distributed to Duke Energy Immediately following the debt transaction, the MS Members collectively acquired a 49% membership interest in the Crescent JV from Duke Energy for a purchase price of approximately $415 million A 2% interest in the Crescent JV was also issued by the joint venture to the President and Chief Executive Officer of Crescent which is subject to forfeiture if the executive voluntarily leaves the employment of the Crescent JV within a three year period Additionally, this 2% interest can be put back to the Crescent JV after three years or possibly earlier upon the occurrence of certain events at an amount equal to 2% of the fair value of the Crescent JV's equity as of the put date Therefore, the Crescent JV will accrue the obligation related to the put as a liability over the three year forfeiture period Accordingly, Duke Energy has an effective 50% ownership in the equity of Crescent JV for financial reporting purposes In conjunction with this transaction, Duke Energy recognized a pre-tax gain on the sale of approximately $250 million which has been classified as a component of Gains (Losses) on Sales of Other Assets and Other, net in the accompanying Consolidated Statement of Operations for the year ended December 31, 2006 As a result of the Crescent transaction, Duke Energy no longer controls the Crescent JV and on September 7, 2006 deconsolidated its investment in Crescent and subsequently will account for its investment in the Crescent JV utilizing the equity method of accounting Duke Energy's equity investment in the Crescent JV is approximately $180 million as of December 31, 2006 The proceeds from the sale were recorded on the Consolidated Statements of Cash Flows as follows: approximately $1 2 billion in long-term debt proceeds, net of issuance costs, were classified as Proceeds from the issuance of long-term debt within Financing Activities, and approximately $380 million, which represents cash received from the MS Members net of cash held by Crescent as of the transaction date, were classified as Net proceeds from the sales of and distributions from equity investments and other assets, and sales of and collections on notes receivable within Investing Activities
- Natural Gas Transmission's sale of certain Stone Mountain natural gas gathering system assets resulted in proceeds of $18 million (which is reflected in Net proceeds from the sales of equity investments and other assets, and sales of and collections on notes receivable within Cash Flows from Investing Activities in the Consolidated Statements of Cash Flows), and pre-tax gain of $5 million which was recorded in Gains (Losses) on Sales of Other Assets and Other, net in the accompanying Consolidated Statements of Operations In addition, Natural Gas Transmission's sale of stock, received as consideration for the settlement of a customers' transportation contract, resulted in proceeds of approximately $29 million (which is reflected in Other, assets within Cash Flows from Operating Activities in the Consolidated Statements of Cash Flows) and a pre-tax gain of $29 million, of which

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

approximately $28 million was recorded in Gains (Losses) on Sales of Other Assets and Other, net and approximately $1 million was recorded in Other Income and Expenses, net in the accompanying Consolidated Statements of Operations (see Note 9)

- Commercial Power's sale of emission allowances, which resulted in proceeds of $136 million and pre-tax losses on sales of approximately $29 million (see Note 10), which was recorded in Gains (Losses) on Sales of Other Assets and Other, net, in the Consolidated Statements of Operations This was partially offset by the sale of the Pine Mountain synthetic fuel facility, which resulted in proceeds of approximately $8 million and a pre-tax gain of approximately $6 million, which was recorded in Gains (Losses) on Sales of Other Assets and Other, net, in the Consolidated Statements of Operations
- As a result of a settlement of a property insurance claim, Natural Gas Transmission received proceeds of approximately $30 million and recognized a pre-tax gain of approximately $10 million, which was recorded in Gains (Losses) on Sales of Other Assets and Other, net, in the Consolidated Statements of Operations

For the period from January 1, 2006 to September 7, 2006, Crescent commercial and multi-family real estate sales resulted in $254 million of proceeds and $201 million of net pre-tax gains recorded in Gains on Sales of Investments in Commercial and Multi-Family Real Estate on the Consolidated Statements of Operations Sales primarily consisted of two office buildings at Potomac Yard in Washington, D C for a pre-tax gain of $81 million and land at Lake Keowee in northwestern South Carolina for a pre-tax gain of $52 million, as well as several other large land tract sales

For the year ended December 31, 2005, the sale of other assets, businesses and equity investments resulted in approximately $2 3 billion in proceeds, pre-tax gains of $534 million recorded in Gains (Losses) on Sales of Other Assets and Other, net, on the accompanying Consolidated Statements of Operations and pre-tax gains of $1,225 million recorded in Gains (Losses) on Sales and Impairments of Equity Method Investments on the accompanying Consolidated Statements of Operations These sales exclude assets that were held for sale and reflected in discontinued operations, both of which are discussed in Note 13, and commercial and multi-family real estate sales by Crescent which are discussed separately below Significant sales of other assets and equity investments during 2005 are detailed as follows:

- In February 2005, DEFS sold its wholly owned subsidiary Texas Eastern Products Pipeline Company, LLC (TEPPCO GP), which is the general partner of TEPPCO Partners, LP (TEPPCO LP), for approximately $1 1 billion and Duke Energy sold its limited partner interest in TEPPCO LP for approximately $100 million, in each case to Enterprise GP Holdings LP (EPCO), an unrelated third party These transactions resulted in pre-tax gains of $1 2 billion, which were recorded in Gains (Losses) on Sales and Impairments of Equity Method Investments in the Consolidated Statements of Operations Minority Interest Expense of $343 million was recorded in the accompanying Consolidated Statements of Operations to reflect ConocoPhillips' proportionate share in the pre-tax gain on sale of TEPPCO GP Additionally, in July 2005, Duke Energy completed the agreement with ConocoPhillips, Duke Energy's co-equity owner in DEFS, to reduce Duke Energy's ownership interest in DEFS from 69 7% to 50% (the DEFS disposition transaction), which results in Duke Energy and ConocoPhillips becoming equal 50% owners in DEFS Duke Energy has received, directly and indirectly through its ownership interest in DEFS, a total of approximately $1 1 billion from ConocoPhillips and DEFS, consisting of approximately $1 0 billion in cash and approximately $0.1 billion of assets The DEFS disposition transaction resulted in a pre-tax gain of approximately $575 million, which was recorded in Gains (Losses) on Sales of Other Assets and Other, net, in the accompanying Consolidated Statements of Operations The DEFS disposition transaction includes the transfer to Duke Energy of DEFS' Canadian natural gas gathering and processing facilities Additionally, the DEFS disposition transaction included the acquisition of ConocoPhillips' interest in the Empress System Subsequent to the closing of the DEFS disposition transaction, effective on July 1, 2005, DEFS is no longer consolidated into Duke Energy's consolidated financial statements and is accounted for by Duke Energy as an equity method investment See Note 8 for the impacts of this transaction on certain cash flow hedges The Canadian natural gas gathering and processing facilities and the Empress System are included in the Natural Gas Transmission segment
- In December 2005, the Duke Energy Income Fund (Income Fund), a Canadian income trust fund, was created to acquire all of the common shares of Duke Energy Midstream Services Canada Corporation (Duke Midstream) from a subsidiary of Duke Energy The Income Fund sold an approximate 40% ownership interest in Duke Midstream for approximately $110 million, which was included in Proceeds from Duke Energy Income Fund within Cash Flows from Financing activities on the Consolidated Statements of Cash Flows In January 2006, a subsequent greenshoe sale of additional ownership interests, pursuant to an overallotment option, in the Income Fund were sold for approximately $10 million Duke Energy retains an ownership interest in the Income Fund of approximately 58% and will continue to operate and manage this business Duke Energy continues to consolidate the results of this business

- In December 2005, Commercial Power recorded a $75 million charge related to the termination of structured power contracts in the Southeast, which was recorded in Gains (Losses) on Sales of Other Assets and Other, net on the accompanying Consolidated Statements of Operations

For the year ended December 31, 2005, Crescent's commercial and multi-family real estate sales resulted in $372 million of proceeds and $191 million of net pre-tax gains recorded in Gains on Sales of Investments in Commercial and Multi-Family Real Estate on the Consolidated Statements of Operations Sales included a large land sale in Lancaster County, South Carolina that resulted in $42 million of pre-tax gains, and several other "legacy" land sales Additionally, Crescent had $45 million in pre-tax income related to a distribution from an interest in a portfolio of commercial office buildings which was recognized in Other Income and Expenses, net, in the accompanying Consolidated Statements of Operations (see Note 24).

For the year ended December 31, 2004, the sale of other assets and businesses (which excludes assets held for sale as of December 31, 2004 and discontinued operations, both of which are discussed in Note 13, and sales by Crescent which are discussed separately below) resulted in approximately $715 million in cash proceeds plus a $48 million note receivable from the buyers, and net pre-tax losses of $416 million recorded in Gains (Losses) on Sales of Other Assets and Other, net and pre-tax losses of $4 million recorded in (Losses) Gains on Sales and Impairments of Equity Method Investments on the Consolidated Statements of Operations (Losses) Gains on Sales and Impairments of Equity Method Investments included a $23 million impairment charge, which is discussed in Note 12 Significant sales of other assets in 2004 are detailed as follows:

- Natural Gas Transmission's asset sales totaled $25 million in net proceeds. Those sales resulted in total pre-tax gains of approximately $33 million, of which $17 million was recorded in Gains (Losses) on Sales of Other Assets and Other, net and $16 million was recorded in Gains (Losses) on Sales and Impairments of Equity Method Investments in the Consolidated Statements of Operations Significant sales included the sale of storage gas related to the Canadian distribution operations, the sale of Natural Gas Transmission's interest in the Millennium Pipeline, and the sale of land.
- Field Services asset sales totaled $13 million in net proceeds Those sales resulted in gains of $2 million which were recorded in Gains (Losses) on Sales of Other Assets and Other, net in the Consolidated Statements of Operations These sales consisted of multiple small sales
- Commercial Power's asset sales totaled approximately $464 million in net proceeds and a $48 million note receivable Those sales resulted in pre-tax losses of $360 million which were recorded in Gains (Losses) on Sales of Other Assets and Other, net in the Consolidated Statements of Operations Significant sales included:
- Commercial Power's eight natural gas-fired merchant power plants in the Southeastern United States: Hot Spring (Arkansas); Murray and Sandersville (Georgia); Marshall (Kentucky); Hinds, Southaven, Enterprise and New Albany (Mississippi); and certain other power and gas contracts (collectively, the Southeast Plants) Duke Energy decided to sell the Southeast Plants in 2003, and recorded an impairment charge of $1 3 billion in 2003 since the assets' carrying values exceeded their estimated fair values The sale of those assets to KGen Partners LLC (KGen) obtained all required regulatory approvals and consents and closed on August 5, 2004 This transaction resulted in a pre-tax loss of approximately $360 million recorded in Gains (Losses) on Sales of Other Assets and Other, net in the 2004 Consolidated Statement of Operations Nearly all of the loss was recognized in the first quarter of 2004 to reduce the assets' carrying values to their estimated fair values, and approximately $4 million of the loss was recognized in the third quarter of 2004 upon closing The fair value of the plants used for recording the loss in the first quarter was based on the sales price of approximately $475 million, as announced on May 4, 2004 The actual sales price consisted of $420 million of cash and a $48 million note receivable from KGen, which bears variable interest at the London Interbank Offered Rate (LIBOR) plus 13 625% per annum, compounded quarterly The note is secured by a fourth lien on (i) substantially all of KGen's assets and (ii) stock of KGen LLC (KGen's owner), each subject to certain permitted liens and a first lien on cash in certain KGen accounts The note was repaid in full during 2005

Duke Energy retained certain guarantees related to the sold assets In conjunction with the sale. Duke Energy arranged a letter of credit with a face amount of $120 million in favor of Georgia Power Company, to secure obligations of a KGen subsidiary under a seven-year power sales agreement, commencing in May 2005, under which KGen will provide power from one of the plants to Georgia Power Duke Energy is the ultimate obligor to the letter of credit provider, but KGen has an obligation to reimburse Duke Energy for any payments made by it under the letter of credit, as well as expenses incurred by Duke Energy in connection with the letter of credit In February 2007, this guarantee was cancelled (see Note 18) Duke Energy will continue to provide services

DUKE ENERGY CORPORATION
Notes To Consolidated Financial Statements—(Continued)

under a long-term operating agreement for one of the plants As a result of Duke Energy's significant continuing involvement in the operations of the plants, this transaction did not qualify for discontinued operations presentation, as prescribed by SFAS No 144 However, this continuing involvement did not prohibit sale accounting under SFAS No 66, "Accounting for Sales of Real Estate "

- During 2004, a 25% undivided interest in Commercial Power's Vermillion facility was sold for proceeds of approximately $44 million This sale was anticipated in 2003 and, therefore, an $18 million loss on sale was recorded during 2003
- International Energy completed the sale of its 30% equity interest in Compañia de Nitrógeno de Cantarell, S A de C V (Cantarell) a nitrogen production and delivery facility in the Bay of Campeche, Gulf of Mexico on September 8, 2004 The sale resulted in $60 million in net proceeds and an approximate $2 million pre-tax gain recorded to Gains (Losses) on Sales and Impairments of Equity Method Investments on the Consolidated Statements of Operations A $13 million non-cash charge to Operation, Maintenance and Other expenses on the Consolidated Statements of Operations, related to a note receivable from Cantarell, was recorded in the first quarter of 2004
- Additional asset and business sales in 2004 totaled $222 million in net proceeds Those sales resulted in net pre-tax losses of $74 million, of which $75 million was recorded in Gains (Losses) on Sales of Other Assets, net and a $1 million gain was recorded in Gains (Losses) on Sales and Impairments of Equity Method Investments in the Consolidated Statements of Operations. These sales primarily related to some contracts at Duke Energy Trading and Marketing, LLC (DETM) DETM held a net liability position in certain contracts and, as part of the sale, DETM paid a third party net cash payments of $99 million related to the sale of these assets which are included in Cash Flows from Operating Activities This resulted in a net loss of $65 million recorded in Gains (Losses) on Sales of Other Assets and Other, net in the 2004 Consolidated Statement of Operations Other significant sales included Duke Energy Royal LLC's interest in six energy service agreements and DukeSolutions Huntington Beach, LLC

For the year ended December 31, 2004, Crescent's commercial and multi-family real estate sales resulted in $606 million of proceeds, and $192 million of net gains recorded in Gains on Sales of Investments in Commercial and Multi-Family Real Estate on the Consolidated Statements of Operations Significant sales included commercial project sales, resulting primarily from the sale of a commercial project in the Washington, D C area in March; real estate sales due primarily to the sale of the Alexandria and Arlington land tracts in the Washington, D C area; and several large land tract sales

3. Business Segments

In conjunction with Duke Energy's merger with Cinergy, effective with the second quarter of 2006, Duke Energy adopted new business segments that management believes properly align the various operations of Duke Energy with how the chief operating decision maker views the business Duke Energy operates the following business units: U S Franchised Electric and Gas, Natural Gas Transmission, Field Services, Commercial Power, International Energy and Crescent Prior to Duke Energy's sale of an effective 50% ownership interest in Crescent in September 2006 (see below), this segment represented Duke Energy's 100% ownership of Crescent Resources, LLC Duke Energy's chief operating decision maker regularly reviews financial information about each of these business units in deciding how to allocate resources and evaluate performance All of the Duke Energy business units are considered reportable segments under SFAS No 131 Prior to the September 2005 announcement of the exiting of the majority of former DENA's businesses (see below), former DENA's operations were considered a separate reportable segment The term DENA, as used throughout the Notes to Consolidated Financial Statements, refers to the former merchant generation operations in the Western and Eastern U S , as well as operations in the Midwest and Southeast Under Duke Energy's new segment structure, the merchant generation operations of the Midwest and Southeast are presented in continuing operations as a component of the Commercial Power segment for all periods presented and the Western and Eastern operations are presented as a component of discontinued operations within Other for all periods presented. Prior to the change in business segments, former DENA's continuing operations, which primarily include the merchant generation operations in the Midwest and Southeast, were included in Other in 2005 and as a component of the DENA segment in all prior periods, and discontinued operations were included in the former DENA segment for all periods There is no aggregation within Duke Energy's defined business segments.

U S Franchised Electric and Gas generates, transmits, distributes and sells electricity in central and western North Carolina, western South Carolina, southwestern Ohio, central and southern Indiana, and northern Kentucky U S Franchised Electric and Gas also transports and sells natural gas in southwestern Ohio and northern Kentucky It conducts operations primarily through Duke Energy Carolinas, Duke

DUKE ENERGY CORPORATION
Notes To Consolidated Financial Statements—(Continued)

Energy Ohio, Duke Energy Indiana and Duke Energy Kentucky These electric and gas operations are subject to the rules and regulations of the FERC, the NCUC, the Public Service Commission of South Carolina (PSCSC), the Public Utilities Commission of Ohio (PUCO), the IURC and the Kentucky Public Service Commission (KPSC).

Cinergy, a Delaware corporation organized in 1993, owns all outstanding common stock of its public utility companies, Duke Energy Ohio and Duke Energy Indiana, as well as other businesses including (a) cogeneration and energy efficiency investments and (b) natural gas and power marketing and trading operations, conducted primarily through CMT, which was sold to Fortis in October 2006 (see Note 13)

Duke Energy Ohio, an Ohio corporation organized in 1837, is a combination electric and gas public utility company that provides service in the southwestern portion of Ohio and, through its wholly-owned subsidiary Duke Energy Kentucky, in nearby areas of Kentucky Its principal lines of business include generation, transmission, and distribution of electricity, the sale of and/or transportation of natural gas, and power marketing and trading The regulated operations of Duke Energy Ohio are included in the U S Franchised Electric and Gas segment, whereas the unregulated portion of the business is included in the Commercial Power segment

Duke Energy Indiana, an Indiana corporation organized in 1942, is a vertically integrated and regulated electric utility that provides service in central and southern Indiana Its primary line of business is generation, transmission, and distribution of electricity

Natural Gas Transmission provides transportation and storage of natural gas for customers along the U.S. East Coast, the Southeast, and in Canada. Natural Gas Transmission also provides natural gas sales and distribution service to retail customers in Ontario, natural gas processing services to customers in Western Canada and other energy related services Natural Gas Transmission does business primarily through Duke Energy Gas Transmission, LLC Duke Energy Gas Transmission, LLC's natural gas transmission and storage operations in the U S are primarily subject to the FERC's and the U S Department of Transportation's rules and regulations, while natural gas gathering, processing, transmission, distribution and storage operations in Canada are primarily subject to the rules and regulations of the National Energy Board (NEB) and the Ontario Energy Board (OEB) Natural Gas Transmission also includes the results of operations of the McMahon facility and the Canadian gathering and processing facilities transferred to Natural Gas Transmission from DENA and Field Services, respectively, during 2005

Field Services gathers, compresses, processes, transports, trades and markets, and stores natural gas; and fractionates, transports, gathers, treats, processes, trades and markets, and stores NGLs It conducts operations primarily through DEFS, which is owned 50 percent by ConocoPhillips and 50 percent by Duke Energy Field Services gathers raw natural gas through gathering systems located in seven major natural gas producing regions: Permian, Mid-Continent, East Texas-North Louisiana, South, Central, Rocky Mountain and Gulf Coast

In February 2005, DEFS sold its wholly owned subsidiary TEPPCO GP, which is the general partner of TEPPCO LP, and Duke Energy sold its limited partner interest in TEPPCO LP, in each case to EPCO, an unrelated third party As a result of the DEFS disposition transaction discussed in Note 2, Duke Energy deconsolidated its investment in DEFS effective July 1, 2005 and subsequently has accounted for it as an investment utilizing the equity method of accounting In connection with the DEFS disposition transaction, DEFS transferred its Canadian natural gas gathering and processing facilities to Duke Energy's Natural Gas Transmission segment

See Note 25 for the impacts on Duke Energy's business segments of the spin-off of Duke Energy's natural gas transmission businesses to Spectra Energy effective January 2, 2007

Commercial Power owns, operates and manages non-regulated merchant power plants and engages in the wholesale marketing and procurement of electric power, fuel and emission allowances related to these plants as well as other contractual positions. Commercial Power also develops and implements customized energy solutions Commercial Power's generation asset fleet consists of Duke Energy Ohio's non-regulated generation in Ohio and the five Midwestern gas-fired merchant generation assets that were a portion of former DENA Commercial Power's assets comprise approximately 8,100 megawatts (MW) of power generation primarily located in the Midwestern United States The asset portfolio has a diversified fuel mix with base-load and mid-merit coal-fired units as well as combined cycle and peaking natural gas-fired units Most of the generation asset output in Ohio has been contracted through the Rate Stabilization Plan (RSP).

International Energy operates and manages power generation facilities, and engages in sales and marketing of electric power and natural gas outside the U S and Canada It conducts operations primarily through Duke Energy International, LLC (DEI) and its activities target power generation in Latin America Additionally, International Energy owns equity investments in National Methanol Company (NMC), located in Saudi Arabia, which is a leading regional producer of methanol and methyl tertiary butyl ether (MTBE), Compania de Servicios de Compression de Campeche, S A (Campeche), located in the Cantarell oil field in the Bay of Campeche, Mexico, which compresses and dehydrates natural gas and extracts NGLs, and Attiki Gas Supply S A (Attiki), located in Athens, Greece, which is a natural gas distributor

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

Crescent develops and manages high-quality commercial, residential and multi-family real estate projects primarily in the Southeastern and Southwestern United States Some of these projects are developed and managed through joint ventures Crescent also manages "legacy" land holdings in North and South Carolina. On September 7, 2006, Duke Energy deconsolidated Crescent due to a reduction in ownership and its inability to exercise control over Crescent (see Note 2) Crescent has been accounted for as an equity method investment since the date of deconsolidation

The remainder of Duke Energy's operations is presented as "Other" While it is not considered a business segment, Other primarily includes the following:

- The remaining portion of Duke Energy's business formerly known as DENA, including its 100% owned affiliates Duke Energy Marketing America, LLC and Duke Energy Marketing Canada Corp Duke Energy also participates in DETM. DETM is 40% owned by ExxonMobil Corporation and 60% owned by Duke Energy During the third quarter of 2005, Duke Energy's Board of Directors authorized and directed management to execute the sale or disposition of substantially all of former DENA's remaining assets and contracts outside the Midwestern United States and certain contractual positions related to the Midwestern assets The exit plan was completed in the second quarter of 2006 (see Note 13) In addition, management will continue to wind down the limited remaining operations of DETM As a result of this exit plan, the results of operations for most of former DENA's businesses which Duke Energy has exited have been reflected as discontinued operations in the accompanying Consolidated Statements of Operations for all years presented Continuing operations related to the former DENA operations within Other consist primarily of DETM, which management continues to wind down.
- Other also includes certain unallocated corporate costs, certain discontinued hedges, DukeNet Communications, LLC (DukeNet), Bison Insurance Company Limited (Bison), Duke Energy's wholly owned, captive insurance subsidiary, Cinergy's equity financing business and Duke Energy's 50% interest in Duke/Fluor Daniel (D/FD) DukeNet develops, owns and operates a fiber optic communications network, primarily in the Carolinas, serving wireless, local and long-distance communications companies, internet service providers and other businesses and organizations During 2003, Duke Energy determined that it would exit the refined products business at Duke Energy Merchants, LLC (DEM) in an orderly manner, and continues to unwind its portfolio of contracts As of December 31, 2006, DEM had completed the exit of its business, and all of the results of operations have been classified as discontinued operations in the accompanying Consolidated Statements of Operations for all periods presented Bison's principal activities, as a captive insurance entity, include the insurance and reinsurance of various business risks and losses, such as workers compensation, property, business interruption and general liability of subsidiaries and affiliates of Duke Energy Bison also participates in reinsurance activities with certain third parties, on a limited basis Cinergy has a business which invests in start up businesses utilizing new energy technologies as well as technologies utilizing energy infrastructure, such as broadband over power line services D/FD is a 50/50 partnership between subsidiaries of Duke Energy and Fluor Corporation (Fluor) During 2003, Duke Energy and Fluor announced that they would dissolve D/FD and adopted a plan for an orderly wind-down of the D/FD business The wind-down has been substantially completed as of December 31, 2006. Previously, D/FD provided comprehensive engineering, procurement, construction, commissioning and operating plant services for fossil-fueled electric power generating facilities worldwide
- During 2003, Duke Energy decided to exit the merchant finance business conducted by Duke Capital Partners, LLC (DCP) DCP had been previously included in Other As of December 31, 2005, Duke Energy had exited the merchant finance business, and all of the results of operations for DCP have been classified as discontinued operations in the accompanying Consolidated Statements of Operations
- During the first quarter of 2005, Duke Energy discontinued hedge accounting for certain contracts related to Field Services' commodity price risk and changes in the fair value of these contracts subsequent to hedge discontinuance have been classified in Other See Note 8 for further discussion.

Duke Energy's reportable segments offer different products and services and are managed separately as business units. Accounting policies for Duke Energy's segments are the same as those described in Note 1 Management evaluates segment performance based on earnings before interest and taxes from continuing operations, after deducting minority interest expense related to those profits (EBIT)

On a segment basis, EBIT excludes discontinued operations, represents all profits from continuing operations (both operating and non-operating) before deducting interest and taxes, and is net of the minority interest expense related to those profits Cash, cash equivalents and short-term investments are managed centrally by Duke Energy, so the associated realized and unrealized gains and losses from foreign currency transactions and interest and dividend income on those balances are excluded from the segments' EBIT

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

Transactions between reportable segments are accounted for on the same basis as revenues and expenses in the accompanying Consolidated Financial Statements

Business Segment Data[a]

	Unaffiliated Revenues	Intersegment Revenues	Total Revenues	Segment EBIT/ Consolidated Earnings from Continuing Operations before Income Taxes	Depreciation and Amortization	Capital and Investment Expenditures	Segment Assets[b]
				(in millions)			
Year Ended December 31, 2006							
U.S. Franchised Electric and Gas	$ 8,077	$ 21	$ 8,098	$ 1,811	$ 1,280	$ 2,381	$ 34,346
Natural Gas Transmission	4,515	8	4,523	1,438	480	790	19,002
Field Services[f]	—	—	—	569	—	—	1,233
Commercial Power[e]	1,396	6	1,402	21	160	209	6,826
International Energy	961	—	961	139	77	58	3,332
Crescent[c][g]	221	—	221	532	1	507	180
Total reportable segments	15,170	35	15,205	4,510	1,998	3,945	64,919
Other[e]	14	128	142	(581)	51	131	3,810
Eliminations and reclassifications	—	(163)	(163)	—	—	—	(29)
Interest expense	—	—	—	(1,253)	—	—	—
Interest income and other[d]	—	—	—	186	—	—	—
Total consolidated	$ 15,184	$ —	$ 15,184	$ 2,862	$ 2,049	$ 4,076	$ 68,700
Year Ended December 31, 2005							
U.S. Franchised Electric and Gas	$ 5,413	$ 19	$ 5,432	$ 1,495	$ 962	$ 1,350	$ 18,739
Natural Gas Transmission	3,955	100	4,055	1,388	458	930	18,823
Field Services[f]	5,470	60	5,530	1,946	143	86	1,377
Commercial Power[e]	102	46	148	(118)	60	2	1,619
International Energy	745	—	745	314	64	23	2,962
Crescent[c][g]	495	—	495	314	1	599	1,507
Total reportable segments	16,180	225	16,405	5,339	1,688	2,990	45,027
Other[e]	117	(45)	72	(518)	40	29	9,402
Eliminations and reclassifications	—	(180)	(180)	—	—	—	294
Interest expense	—	—	—	(1,066)	—	—	—
Interest income and other[d]	—	—	—	56	—	—	—
Total consolidated	$ 16,297	$ —	$ 16,297	$ 3,811	$ 1,728	$ 3,019	$ 54,723
Year Ended December 31, 2004							
U.S. Franchised Electric and Gas	$ 5,045	$ 24	$ 5,069	$ 1,467	$ 863	$ 1,126	$ 18,062
Natural Gas Transmission	3,194	157	3,351	1,329	431	544	17,783
Field Services[f]	10,036	8	10,044	367	285	202	6,265
Commercial Power[e]	(26)	205	179	(479)	69	7	1,726
International Energy	619	—	619	222	58	28	3,058
Crescent[c][g]	437	—	437	240	2	568	1,317
Total reportable segments	19,305	394	19,699	3,146	1,708	2,475	48,211
Other[e]	291	(100)	191	(207)	42	54	7,139
Eliminations and reclassifications	—	(294)	(294)	—	—	—	420
Interest expense	—	—	—	(1,282)	—	—	—
Interest income and other[d]	—	—	—	96	—	—	—
Total consolidated	$ 19,596	$ —	$ 19,596	$ 1,753	$ 1,750	$ 2,529	$ 55,770

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

(a) Segment results exclude results of entities classified as discontinued operations

(b) Includes assets held for sale

(c) Capital expenditures for residential real estate are included in operating cash flows and were $322 million for the period from January 1, 2006 through the date of deconsolidation (September 7, 2006), $355 million in 2005 and $322 million in 2004

(d) Other includes foreign currency transaction gains and losses, and additional minority interest expense not allocated to the segment results

(e) Amounts associated with former DENA operations are included in Other for all periods presented, except for the Midwestern generation and Southeast operations, which are reflected in Commercial Power

(f) In July 2005, Duke Energy completed the agreement with ConocoPhillips to reduce Duke Energy's ownership interest in DEFS from 69 7% to 50% Field Services segment data includes DEFS as a consolidated entity for periods prior to July 1, 2005 and as an equity method investment for periods after June 30, 2005

(g) In September 2006, Duke Energy completed a joint venture transaction of Crescent (see Note 2) As a result, Crescent segment data includes Crescent as a consolidated entity for periods prior to September 7, 2006 and as an equity method investment for periods subsequent to September 7, 2006

Geographic Data

	U.S.	Canada	Latin America	Other Foreign	Consolidated
			(in millions)		
2006					
Consolidated revenues	$ 10,710	$ 3,472	$ 961	$ 41	$ 15,184
Consolidated long-lived assets	43,468	10,541	2,474	245	56,728
2005					
Consolidated revenues	$ 12,147	$ 3,366	$ 740	$ 44	$ 16,297
Consolidated long-lived assets	29,658	10,544	2,241	228	42,671
2004					
Consolidated revenues	$ 16,861	$ 2,067	$ 611	$ 57	$ 19,596
Consolidated long-lived assets	30,960	9,902	2,136	233	43,231

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

4. Regulatory Matters

Regulatory Assets and Liabilities. Duke Energy's regulated operations are subject to SFAS No 71 Accordingly, Duke Energy records assets and liabilities that result from the regulated ratemaking process that would not be recorded under GAAP for non-regulated entities (For further information see Note 1)

Duke Energy's Regulatory Assets and Liabilities:

	As of December 31, 2006	As of December 31, 2005	Recovery/Refund Period Ends
	(in millions)		
Regulatory Assets[a]			
Net regulatory asset related to income taxes[b]	$ 1,361	$ 1,338	(l)
Accrued pension and post retirement[c] [r]	975	—	(p)
ARO costs[c]	463	546	2043
Regulatory Transition Charges (RTC)[c]	331	—	2011
Gasification services agreement buyout costs[c]	207	—	2018
Deferred debt expense[d]	192	166	2039
Vacation accrual[c]	121	80	2007
Post-in-service carrying costs and deferred operating expense[c]	92	—	2065
Under-recovery of fuel costs[f][i]	61	—	2008
Hedge costs and other deferrals[c]	48	—	2007
Regional Transmission Organization (RTO)[q]	41	41	(o)
Other[c]	180	148	(p)
Total Regulatory Assets	$ 4,072	$ 2,319	
Regulatory Liabilities[a]			
Removal costs[d][h]	$ 2,345	$ 1,670	(n)
Other deferred tax credits[d][f][h]	5	8	(f)
Nuclear property and liability reserves[d][h]	173	167	2043
Gas purchase costs[g]	173	—	2007
Purchased capacity costs[e][j]	107	121	(k)
Demand-side management costs[e][h]	78	59	(m)
Deferred emission allowance revenue	41	—	(p)
Over-recovery of fuel costs[f][g]	20	76	2007
North Carolina clean air compliance[d][h]	—	164	2011
Other[h]	116	73	(p)
Total Regulatory Liabilities	$ 3,058	$ 2,338	

(a) All regulatory assets and liabilities are excluded from rate base unless otherwise noted

(b) Natural Gas Transmission's amounts of $848 million at December 31, 2006 and $954 million at December 31, 2005 are expected to be included in future rate filings U.S Franchised Electric and Gas's amounts of $513 million at December 31, 2006 and $384 million at December 31, 2005 are included in rate base

(c) Included in Other Regulatory Assets and Deferred Debits on the Consolidated Balance Sheets

(d) Included in rate base

(e) Earns a negative return

(f) In 2005, Duke Energy Carolinas reduced the previously recorded excess deferred tax liability by approximately $150 million Additionally, in 2005, Duke Energy Carolinas received approval from the NCUC to credit approximately $100 million against fuel rates for North Carolina retail customers Similarly, the PSCSC granted approval to credit approximately $40 million against fuel rates for South Carolina retail customers These amounts were credited to customer rates during 2006 and 2005 The remaining reduction was achieved by crediting fuel rates for certain wholesale customers and writing off a portion of the balance against income

(g) Included in Accounts Payable on the Consolidated Balance Sheets

(h) Included in Other Deferred Credits and Other Liabilities on the Consolidated Balance Sheets

(i) Included in Receivables on the Consolidated Balance Sheets

(j) Included in Other Current Liabilities and Other Deferred Credits and Other Liabilities on the Consolidated Balance Sheets

(k) Incurred costs were deferred and are being recovered in rates U S Franchised Electric and Gas is currently over-recovered for these costs and is refunding the liability through retail rates Refund period will be determined by the volume of sales

(l) Recovery/refund is over the life of the associated asset or liability

(m) Incurred costs were deferred and are being recovered in rates U S Franchised Electric and Gas is currently over-recovered for these costs in the South Carolina jurisdiction Refund period is dependent on volume of sales and cost incurrence

(n) Liability is extinguished over the lives of the associated assets

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

(o) To be recovered through future transmission rates Recovery period currently unknown

(p) Recovery/Refund period currently unknown

(q) Investment in RTO reclassified as regulatory asset from Other Deferred Credits during 2005 after termination of GridSouth Transco project

(r) Includes $595 million related to adoption of SFAS No 158 (see Note 22) and $380 million related to impacts of purchase accounting as a result of the merger with Cinergy (see Note 2)

Regulatory Merger Approvals As discussed in Note 1 and Note 2, on April 3, 2006, the merger between Duke Energy and Cinergy was consummated to create a newly formed company Duke Energy Holding Corp (subsequently renamed Duke Energy Corporation) As a condition to the merger approval, the PUCO, the KPSC, the PSCSC and the NCUC required that certain merger related savings be shared with consumers in Ohio, Kentucky, South Carolina, and North Carolina, respectively The commissions also required Duke Energy Holding Corp , Cinergy, Duke Energy Ohio, Duke Energy Kentucky, and/or Duke Energy Carolinas to meet additional conditions While the merger itself was not subject to approval by the IURC, the IURC approved certain affiliate agreements in connection with the merger subject to similar conditions Key elements of these conditions include:

- The PUCO required that Duke Energy Ohio provide (i) a rate reduction of approximately $15 million for one year to facilitate economic development in a time of increasing rates and market prices (ii) a reduction of approximately $21 million to its gas and electric consumers in Ohio for one year, with both credits beginning January 1, 2006 In April 2006, the Office of the Ohio Consumers' Council (OCC) filed a Notice of Appeal with the Supreme Court of Ohio, requesting the Court remand the PUCO's merger approval for a full evidentiary hearing The OCC alleged that the PUCO improperly failed to: (i) set the matter for a full evidentiary hearing; (ii) consider evidence regarding the transfer of certain DENA assets to Duke Energy Ohio; and (iii) lift the stay on discovery Duke Energy Ohio and the OCC settled this matter and in June 2006, the Court granted the OCC's motion to dismiss As of December 31, 2006, Duke Energy Ohio has returned $14 million and $20 million, respectively, on each of these rate reductions
- The KPSC required that Duke Energy Kentucky provide $8 million in rate reductions to its customers over five years, ending when new rates are established in the next rate case after January 1, 2008 As of December 31, 2006, Duke Energy Kentucky has returned $1 million to customers on this rate reduction
- The PSCSC required that Duke Energy Carolinas provide a $40 million rate reduction for one year and a three-year extension to the Bulk Power Marketing profit sharing arrangement Approximately $23 million of the rate reduction has been passed through to customers since the ruling by the PSCSC
- The NCUC required that Duke Energy Carolinas provide (i) a rate reduction of approximately $118 million for its North Carolina customers through a credit rider to existing base rates for a one-year period following the close of the merger, and (ii) $12 million to support various low income, environmental, economic development and educationally beneficial programs, the cost of which was incurred in the second quarter of 2006 Approximately $54 million of the rate reduction has been passed through to customers since the ruling by the NCUC

  In its order approving Duke Energy's merger with Cinergy, the NCUC stated that the merger will result in a significant change in Duke Energy's organizational structure which constitutes a compelling factor that warrants a general rate review Therefore, as a condition of its merger approval and no later than June 1, 2007, Duke Energy Carolinas is required to file a general rate case or demonstrate that Duke Energy Carolinas' existing rates and charges should not be changed This review will be consolidated with the proceeding that the NCUC is required to undertake in connection with the North Carolina clean air legislation to review Duke Energy Carolinas' environmental compliance costs The NCUC specifically noted that it has made no determination that the rates currently being charged by Duke Energy Carolinas are, in fact, unjust or unreasonable
- The IURC required that Duke Energy Indiana provide a rate reduction of $40 million to its customers over a one year period and $5 million over a five year period for low-income energy assistance and clean coal technology In April 2006, Citizens Action Coalition of Indiana, Inc , an intervenor in the merger proceeding, filed a Verified Petition for Rehearing and Reconsideration claiming that Duke Energy Indiana should be ordered to provide an additional $5 million in rate reduction to customers to be consistent with the terms of the NCUC's order approving the merger In May 2006, the IURC denied the petition for rehearing and reconsideration As of December 31, 2006, Duke Energy Indiana has returned approximately $27 million to customers on this rate reduction
- The FERC approved the merger without conditions In January 2006, Public Citizen's Energy Program, Citizens Action Coalition of Indiana, Inc , Ohio Partners for Affordable Energy and Southern Alliance for Clean Energy requested rehearing of the FERC approval In February 2006, the FERC issued an order granting rehearing of FERC's order for further consideration On February 5, 2007, after further consideration, the FERC issued an order dismissing the request for a rehearing

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

Spent Nuclear Fuel. Under provisions of the Nuclear Waste Policy Act of 1982, Duke Energy contracted with the DOE for the disposal of spent nuclear fuel The DOE failed to begin accepting spent nuclear fuel on January 31, 1998, the date specified by the Nuclear Waste Policy Act and in Duke Energy's contract with the DOE In 1998, Duke Energy filed a claim with the U S Court of Federal Claims against the DOE related to the DOE's failure to accept commercial spent nuclear fuel by the required date Damages claimed in the lawsuit are based upon Duke Energy's costs incurred as a result of the DOE's partial material breach of its contract, including the cost of securing additional spent fuel storage capacity The matter has been stayed pending the result of ongoing settlement negotiations between Duke Energy and the DOE. Duke Energy will continue to safely manage its spent nuclear fuel until the DOE accepts it Payments made to the DOE for expected future disposal costs are based on nuclear output and are included in the Consolidated Statements of Operations as Fuel Used in Electric Generation and Purchased Power Duke Energy expects resolution of this matter in the first quater of 2007

U.S. Franchised Electric and Gas. *Rate Related Information.* The NCUC, PSCSC, IURC and KPSC approve rates for retail electric and gas sales within their states The PUCO approves rates and market prices for retail electric and gas sales within Ohio. The FERC approves rates for electric sales to wholesale customers served under cost-based rates

NC Clean Air Act Compliance. In 2002, the state of North Carolina passed clean air legislation that freezes electric utility rates from June 20, 2002 to December 31, 2007 (rate freeze period), subject to certain conditions, in order for North Carolina electric utilities, including Duke Energy Carolinas, to significantly reduce emissions of sulfur dioxide (SO_2) and nitrogen oxides (NOx) from coal-fired power plants in the state The legislation allows electric utilities, including Duke Energy Carolinas, to accelerate the recovery of compliance costs by amortizing them over seven years (2003-2009). The legislation provides for significant flexibility in the amount of annual amortization recorded, allowing utilities to vary the amount amortized, within limits, although the legislation does require that a minimum of 70% of the originally estimated total cost of $1 5 billion be amortized within the rate freeze period (2002 to 2007) Duke Energy Carolinas' amortization expense related to this clean air legislation totals approximately $863 million from inception, with approximately $225 million, $311 million and $211 million recorded during the years ended 2006, 2005 and 2004, respectively As of December 31, 2006, cumulative expenditures totaled approximately $828 million, with $403 million, $310 million, and $106 million incurred during the years ended December 31, 2006, 2005 and 2004, respectively, and are included within capital expenditures in Net Cash Used In Investing Activities on the Consolidated Statements of Cash Flows In filings with the NCUC, Duke Energy Carolinas has estimated the costs to comply with the legislation as approximately $1 7 billion Actual costs may be higher than the estimate based on changes in construction costs and Duke Energy Carolinas' continuing analysis of its overall environmental compliance plan Any change in compliance costs will be included in future filings with the NCUC Additionally, federal, state and environmental regulations, including, among other things, the Clean Air Interstate Rule (CAIR), and the Clean Air Mercury Rule (CAMR) could result in additional costs to reduce emissions from our coal-fired power plants

Duke Energy Indiana Environmental Compliance Case. In November 2004, Duke Energy Indiana applied to the IURC for approval of its plan for complying with SO_2, NO_X, and mercury emission reduction requirements Duke Energy Indiana also requested approval of cost recovery for certain proposed compliance projects An evidentiary hearing was held in May 2005 In December 2005, Duke Energy Indiana, the Indiana Office of Utility Consumer Counselor (OUCC), and the Duke Energy Indiana Industrial Group filed a settlement agreement providing for approval of Duke Energy Indiana's compliance plan, and approval of financing, depreciation, and operation and maintenance cost recovery In May 2006, the IURC approved the settlement agreement in its entirety The approved Settlement Agreement provides for: (1) the construction of Phase 1 CAIR and Clean Air Mercury Rule (CAMR) projects with estimated expenditures of approximately $1 08 billion, (2) timely recovery of financing, construction, operation and maintenance cost and depreciation associated with the Phase 1 CAIR and CAMR plan, (3) recovery of emission allowances in connection with SO_2, NOx and mercury, (4) accelerated 20 year depreciation rate, (5) timely recovery of Phase 1 plan development and presentation costs and Phase 2 plan development, engineering and pre-construction, and coal and equipment testing costs, and (6) authority to defer post-in-service AFUDC, depreciation costs and operation and maintenance cost until applicable costs are reflected in rates

Duke Energy Ohio Electric Rate Filings. Duke Energy Ohio operates under a RSP, a Market Based Standard Service Offer (MBSSO) approved by the PUCO in November 2004 In March 2005, the OCC appealed the PUCO's approval of the MBSSO to the Supreme Court of Ohio and the court issued its decision in November 2006 It upheld the MBSSO in virtually every respect but remanded to the PUCO on two issues The Court ordered the PUCO to support a certain portion of its order with reasoning and record evidence and to require Duke Energy Ohio to disclose certain confidential commercial agreements with other parties previously requested by the OCC Duke Energy Ohio has complied with the disclosure order Such confidential commercial agreements are relatively common in the jurisdiction and the PUCO has not allowed production of such agreements in past cases in which the PUCO was presented with a settlement agreement on the basis that they are irrelevant A hearing on remand is expected in March 2007 Duke Energy Ohio has filed for a regulatory extension of the RSP through 2010

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

On August 2, 2006, Duke Energy Ohio filed an application with the PUCO to amend its MBSSO. The proposal provides for continued electric system reliability, a simplified market price structure and clear price signals for customers, while helping to maintain a stable revenue stream for Duke Energy Ohio. The application is pending and Duke Energy Ohio cannot predict the outcome of this proceeding.

Duke Energy Ohio's MBSSO includes a fuel clause recovery component which is audited annually by the PUCO. In January 2006, Duke Energy Ohio entered into a settlement resolving all open issues identified in the 2005 audit. The PUCO approved the settlement in February 2006. Duke Energy and Duke Energy Ohio do not expect the agreement to have a material impact on their consolidated results of operations, cash flows or financial position.

In addition to the fuel clause recovery component, Duke Energy Ohio's MBSSO includes a reserve capacity component known as the System Reliability Tracker, and an Annually Adjusted Component to recover environmental, tax and homeland security costs. In 2006, Duke Energy Ohio filed an application requesting to modify each of these components. After the Ohio Supreme Court issued its remand order in the MBSSO appeal, the PUCO issued an order permitting Duke Energy Ohio to continue to charge its existing market prices (except for the System Reliability Tracker) with true-up to actual costs to be decided at a later date. The PUCO allowed Duke Energy Ohio's System Reliability Tracker to expire by its terms on January 1, 2007. In the meantime, consideration of Duke Energy Ohio's proposed modifications is suspended pending the outcome of the remand case. Duke Energy Ohio does not expect a significant change, if any to the MBSSO components but cannot predict the outcome of the cases. The PUCO is expected to decide these matters in 2007.

Duke Energy Kentucky Electric Rate Case. In May 2006, Duke Energy Kentucky filed an application for an increase in its base electric rates. The application, which sought an increase of approximately $67 million in revenue, or approximately 28 percent, to be effective in January 2007, was filed pursuant to the KPSC's 2003 Order approving the transfer of 1,100 MW of generating assets from Duke Energy Ohio to Duke Energy Kentucky. Duke Energy Kentucky also sought to reinstitute its fuel cost recovery mechanism which had been frozen since 2001, and has proposed to refresh the pricing for the back-up power supply contract to reflect current market pricing. In the fourth quarter of 2006, Duke Energy Kentucky reached a settlement agreement in principle with all parties to this proceeding resolving all the issues raised in the proceeding. Among other things, the settlement agreement provided for a $49 million increase in Duke Energy Kentucky's base electric rates and reinstitution of the fuel cost recovery mechanism. In December 2006, the KPSC approved the settlement agreement.

Duke Energy Kentucky Gas Rate Cases. In 2002, the KPSC approved Duke Energy Kentucky's gas base rate case which included, among other things, recovery of costs associated with an accelerated gas main replacement program. The approval authorized a tracking mechanism to recover certain costs including depreciation and a rate of return on the program's capital expenditures. The Kentucky Attorney General appealed to the Franklin Circuit Court the KPSC's approval of the tracking mechanism as well as the KPSC's subsequent approval of annual rate adjustments under this tracking mechanism. In 2005, both Duke Energy Kentucky and the KPSC requested that the court dismiss these cases. At the present time, Duke Energy and Duke Energy Kentucky cannot predict the timing or outcome of this litigation.

In February 2005, Duke Energy Kentucky filed a gas base rate case with the KPSC requesting approval to continue the tracking mechanism and for a $14 million annual increase in base rates. A portion of the increase is attributable to recovery of the current cost of the accelerated main replacement program in base rates. In December 2005, the KPSC approved an annual rate increase of $8 million and re-approved the tracking mechanism through 2011. In February 2006, the Kentucky Attorney General appealed the KPSC's order to the Franklin Circuit Court, claiming that the order improperly allows Duke Energy Kentucky to increase its rates for gas main replacement costs in between general rate cases, and also claiming that the order improperly allows Duke Energy Kentucky to earn a return on investment for the costs recovered under the tracking mechanism which permits Duke Energy Kentucky to recover its gas main replacement costs. At this time, Duke Energy and Duke Energy Kentucky cannot predict the outcome of this litigation.

Bulk Power Marketing (BPM) Profit Sharing. The NCUC approved Duke Energy Carolinas' proposal in June 2004 to share an amount equal to fifty percent of the North Carolina retail allocation of the profits from certain wholesale sales of bulk power from Duke Energy Carolinas' generating units at market based rates (BPM Profits). Duke Energy Carolinas also informed the NCUC that it would no longer include BPM Profits in calculating its North Carolina retail jurisdictional rate of return for its quarterly reports to the NCUC. As approved by the NCUC, the sharing arrangement provides for fifty percent of the North Carolina allocation of BPM Profits to be distributed through various assistance programs, up to a maximum of $5 million per year. Any amounts exceeding the maximum are used to reduce rates for industrial customers in North Carolina.

On June 28, 2006, the NCUC issued an order ruling on a dispute between Duke Energy Carolinas, the NCUC Public Staff and the Carolina Utility Customers Association (CUCA) regarding the method for determining the incremental costs of emission allowances used to calculate the BPM Profits under the sharing arrangement The Public Staff and CUCA each proposed methods that differ from the method intended by Duke Energy Carolinas when it initially requested approval of the sharing arrangement Duke Energy Carolinas has consistently used its originally intended method since it first implemented the sharing arrangement The NCUC adopted the Public Staff's method and ordered Duke Energy Carolinas to file and implemented a revised rate rider This ruling resulted in an $18 million charge during the year ended December 31, 2006, of which $11 million related to wholesale sales in 2005 On July 17, 2006, Duke Energy Carolinas filed a Motion for Reconsideration requesting that the NCUC reconsider its June 28, 2006 order In the alternative, Duke Energy Carolinas requested that the NCUC make its order effective only prospectively with respect to sharing periods beginning January 1, 2007 Duke Energy Carolinas also requested that if the NCUC was not inclined to grant its request to reinstate its proposed rider, then the NCUC should approve Duke Energy Carolinas' withdrawal of the rider at its option. On September 15, 2006, Duke Energy Carolinas and the Public Staff filed an Offer of Settlement under which Duke Energy's method would be used through June 30, 2006 and the Public Staff's method would be used from July 1, 2006 through the end of the sharing arrangement Additionally, the sharing arrangement would be extended for the shorter of 1 year (through December 31, 2008) or the effective date of a general rate order from the NCUC addressing the ratemaking treatment of BPM revenues In December 2006, the NCUC approved the settlement, after an evidentiary hearing, and Duke Energy Carolinas reversed the $18 million charge previously recognized

Other. U S Franchised Electric and Gas is engaged in planning efforts to meet projected load growth in its service territory Long-term projections indicate a need for significant capacity additions, which may include new nuclear, integrated gasification combined cycle (IGCC), coal facilities or gas fired generation units Because of the long lead times required to develop such assets, U S Franchised Electric and Gas is taking steps now to ensure those options are available In March 2006, Duke Energy Carolinas announced that it has entered into an agreement with Southern Company to evaluate potential construction of a new nuclear plant at a site jointly owned in Cherokee County, South Carolina With selection of the Cherokee County site, Duke Energy Carolinas is moving forward with previously announced plans to develop an application to the U S Nuclear Regulatory Commission (NRC) for a combined construction and operating license (COL) for two Westinghouse AP1000 (advanced passive) reactors Each reactor is capable of producing approximately 1,117 MW The COL application submittal to the NRC is anticipated in late 2007 or early 2008 Submitting the COL application does not commit Duke Energy Carolinas to build nuclear units On September 20, 2006, Duke Energy Carolinas filed an application with the NCUC for assurance that pursuit of the proposed nuclear plant (the William States Lee III Nuclear Station) is prudent and that Duke Energy Carolinas will be allowed to recover prudently incurred expenses related to its development and evaluation of the proposed William States Lee III Nuclear Station Specifically, Duke Energy Carolinas requests an NCUC order (1) finding that work performed by Duke Energy Carolinas to ensure the availability of nuclear generation by 2016 for its customers is prudent and consistent with the promotion of adequate, reliable, and economical utility service to the citizens of North Carolina and the polices expressed in North Carolina General Statute 62-2, and (2) providing expressly that Duke Energy Carolinas may recover in rates, in a timely fashion, the North Carolina allocable portion of its share of costs prudently incurred to evaluate and develop a new nuclear generation facility through December 31, 2007, whether or not a new nuclear facility is constructed The NCUC held oral arguments on January 9, 2007, and briefs were filed on February 14, 2007 Duke Energy Carolinas expects the NCUC to rule on its application in the first quarter of 2007

On June 2, 2006, Duke Energy Carolinas also filed an application with the NCUC for a Certificate of Public Convenience and Necessity (CPCN) to construct two 800 MW state of the art coal generation units at its existing Cliffside Steam Station in North Carolina The NCUC held public hearings in August 2006, and an evidentiary hearing in Raleigh, North Carolina concluded on September 14, 2006 Post-hearing briefs and proposed orders were filed on October 13, 2006 After the evidentiary hearing, Duke Energy Carolinas received competitive proposals for two major scopes of equipment for the Cliffside Project which suggest that the capital costs for these major components are increasing significantly due to various market pressures that will likely impact utility generation construction projects across the United States In October 2006, Duke Energy made a filing with the NCUC related to the Duke Energy Carolinas' request for a CPCN for the Cliffside project In this filing, Duke Energy stated that due to the rising costs described above, the cost of building the Cliffside units could be approximately $3 billion, excluding allowance for funds used during construction (AFUDC) The costs described above are expected to continue to increase causing the overall cost of the Cliffside project to increase, until such time as the NCUC issues a CPCN and Duke Energy is able to enter into definitive agreements with necessary material and service providers The NCUC issued orders requiring additional public and evidentiary hearings From January 17, 2007 to January 19, 2007 the NCUC held an evidentiary hearing to consider evidence limited to Duke Energy Carolinas updated cost information for the project On February 28, 2007, the NCUC issued a notice of decision approving the construction of one unit at the Cliffside Steam Station The NCUC stated that it will issue a full order in the near future. Duke Energy will review the NCUC's order, once issued, and determine whether to proceed with the Cliffside Project or consider other alternatives, including additional gas fired generation

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

New energy legislation has been introduced in the current South Carolina legislative session Key elements of the legislation include expansion of the annual fuel clause mechanism to include recovery of costs of reagents (ammonia, limestone, etc) that are consumed in the operation of Duke Energy Carolina's SO_2 and NOx control technologies The cost of reagents for Duke Energy Carolinas in 2007 is expected to be approximately $20 million Subsequent to the enactment of any legislation, Duke Energy Carolinas then will be allowed to recover the South Carolina portion of these costs through the fuel clause The legislation also includes provisions to provide cost recovery assurance for upfront development costs associated with nuclear baseload generation, cost recovery assurance for construction costs associated with nuclear or coal baseload generation, and the ability to recover financing costs for new nuclear or coal baseload generation through annual riders Similar legislation is being discussed in North Carolina and may be introduced in the 2007 legislative session At this time, Duke Energy Carolinas cannot determine which elements of any pending legislation will be passed into law or the potential financial impact of those legislative initiatives

In August 2005, Duke Energy Indiana filed an application with the IURC for approval of study and preconstruction costs related to the joint development of an IGCC project with Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana, Inc (Vectren) Duke Energy Indiana and Vectren reached a Settlement Agreement with the OUCC providing for the recovery of such costs if the IGCC project is approved and constructed and for the partial recovery of such costs if the IGCC project does not go forward The IURC issued an order on July 26, 2006 approving the Settlement Agreement in its entirety

On September 7, 2006, Duke Energy Indiana and Vectren filed a joint petition with the IURC seeking certificates of public convenience and necessity for the construction of a 630 MW IGCC power plant at Duke Energy Indiana's Edwardsport Generating Station in Knox County, Indiana. The petition describes the applicants' need for additional baseload generating capacity and requests timely recovery of all construction and operating costs related to the proposed generating station, including financing costs, together with certain incentive ratemaking treatment Duke Energy Indiana and Vectren filed their cases in chief with the IURC on October 24, 2006 As with Duke Energy Carolinas' Cliffside project, Duke Energy Indiana's estimated costs for the potential IGCC project have also increased Duke Energy Indiana's publicly filed testimony with the IURC indicates that industry (EPRI) total capital requirement estimates for a facility of this type and size are now in the range of $1 6 billion to $2 1 billion (including escalation to 2011 and owners' specific site costs) The case is scheduled for an evidentiary hearing in June 2007 On February 16, 2007, Duke Energy Indiana filed a request for deferral and subsequent cost recovery of the costs expected to be incurred prior to the anticipated date of an order by the IURC regarding Duke Energy Indiana's request for a certificate of public convenience and necessity for the construction of the Edwardsport Generating Station These costs relate to the continued investigation, analysis and development of the IGCC project, and must be incurred, to assure the project can achieve a targeted in-service date of 2011

On August 15, 2006, Duke Energy Indiana filed a petition with the IURC requesting recovery of its costs of purchasing electricity to be produced by a 100 megawatt wind energy farm under development pursuant to a 20-year purchased power agreement between Duke Energy Indiana and Benton County Wind Farm, LLC The IURC issued an order on December 6, 2006 approving recovery of the retail portion of the purchased power cost plus the retail portion of Midwest ISO costs over the 20-year life of the agreement

Duke Energy Indiana recovers its actual fuel costs quarterly through a rate adjustment mechanism. In two recent fuel clause proceedings, certain industrial customers and the Citizens Action Coalition of Indiana, Inc have intervened and sub-dockets have been established to address issues raised by the OUCC and the intervenors concerning the allocation of fuel costs between native load customers and non-native load sales, the reasonableness of various Midwest Independent Transmission System Operator, Inc (Midwest ISO) costs for which Duke Energy Indiana has sought recovery and Duke Energy Indiana's recovery of costs associated with certain power hedging activities Duke Energy Indiana is defending its practices, its costs, and the allocation of such costs A hearing was conducted in one of these proceedings on September 20, 2006 A decision is expected in the first quarter of 2007 An evidentiary hearing in the second proceeding is set to begin in May 2007 The IURC has authorized Duke Energy Indiana to collect through rates the costs which it sought recovery in the two sub-docket proceedings, subject to refund pending the outcome of these proceedings. Duke Energy cannot predict the outcome of these proceedings but does not expect the outcome to be material to its consolidated results of operations, cash flows or financial position

In April 2005, the PUCO issued an order opening a statewide investigation into riser leaks in gas pipeline systems throughout Ohio The investigation followed four explosions since 2000 caused by gas riser leaks, including an April 2000 explosion in Duke Energy Ohio's service area In November 2006, the PUCO Staff released the expert report, which concluded that certain types of risers are prone to leaks under various conditions, including over-tightening during initial installation The PUCO Staff recommended that natural gas companies continue to monitor the situation and study the cause of any further riser leaks to determine whether further remedial action is war -

ranted Duke Energy Ohio has approximately 87,000 of these risers on its distribution system If the PUCO orders natural gas companies to replace all of these risers, Duke Energy Ohio estimates a replacement cost of $35 million At this time, Duke Energy Ohio cannot predict the outcome or the impact of the statewide Ohio investigation

In April 2006, the FERC issued an order on the Midwest ISO's revisions to its Transmission and Energy Markets Tariffs regarding its RSG The FERC found that the Midwest ISO violated the tariffs when it did not charge RSG costs to virtual supply offers The FERC, among other things, ordered the Midwest ISO to recalculate the rate and make refunds to customers, with interest, to reflect the correct allocation of RSG costs Duke Energy Shared Services, on behalf of Duke Energy Indiana and Duke Energy Ohio, filed a Request for Rehearing, and in October 2006, the FERC issued an order which, among other things, granted rehearing on the issue of refunds The FERC stated that it would not require recalculation of the rates and, as such, refunds are no longer required As a result, neither Duke Energy Ohio nor Duke Energy Indiana believe that this issue will have a material effect on their consolidated results of operations, cash flows, or financial position

FERC To Issue Electric Reliability Standards Consistent with reliability provisions of the Energy Policy Act of 2005, on July 20, 2006, FERC issued its Final Rule certifying NERC as the Electric Reliability Organization (ERO) NERC has filed over 100 proposed reliability standards with FERC FERC's proposed action to approve a large number of these standards will result in those standards becoming mandatory and enforceable for the 2007 peak summer season Other reliability standards will become mandatory and enforceable thereafter Duke Energy does not believe that the issuance of these standards will have a material impact on its consolidated results of operations, cash flows, or financial position.

Duke Energy Carolinas "Independent Entity" to Perform Transmission Functions On December 19, 2005, the FERC approved a plan filed by Duke Energy Carolinas to establish an "Independent Entity" (IE) to serve as a coordinator of certain transmission functions and an "Independent Monitor" (IM) to monitor the transparency and fairness of the operation of Duke Energy Carolinas' transmission system Under the proposal, Duke Energy Carolinas remains the owner and operator of the transmission system with responsibility for the provision of transmission service under Duke Energy Carolinas' Open Access Transmission Tariff Duke Energy Carolinas has retained the Midwest ISO to act as the IE and Potomac Economics, Ltd to act as the IM The IE and IM began operations on November 1, 2006 Duke Energy Carolinas is not at this time seeking adjustments to its transmission rates to reflect the incremental cost of the proposal, which is not projected to have a material adverse effect on Duke Energy's future consolidated results of operations, cash flows or financial position

Natural Gas Transmission. *Rate Related Information* On August 17, 2006, the NEB approved a settlement for 2006 and 2007 tolls

Union Gas has rates that are approved by the OEB Effective January 1, 2006, Union Gas implemented new rates approved by the OEB in December 2005, reflecting items previously approved Union Gas' earnings for 2006 continue to be subject to the earnings sharing mechanism implemented by the OEB in 2005

In November 2006, Union Gas received a decision from the OEB on the regulation of rates for gas storage services in Ontario The OEB found the storage market is competitive As a result, the OEB will not regulate the rates for storage services to customers outside Union's franchise area or the rates for new storage services to customers within its franchise area Existing storage services to customers within Union's franchise area will continue to be provided at regulated cost-based rates The decision creates an unregulated storage operation within Union Gas, and provides support for new storage investment in Ontario

In December 2006, the OEB issued a final rate order for new rates effective January 1, 2007 The average rate increase is approximately 3 1% and includes the impact of an increase in the common equity component of Union Gas' capital structures from 35% to 36% and a decrease in the allowed return of equity from 9 63% to 8 54%

Rates for the sale of gas of Union Gas are adjusted quarterly to reflect updated commodity price forecasts The difference between the approved and the actual cost of gas incurred in the current period is deferred for future recover from or return to customers, subject to approval by the OEB These differences are directly flowed through to customers and, therefore, no rate of return is earned on the related deferred balances The OEB's review and approval of these gas purchase costs primarily considers the prudence of the cost incurred

As a result of the spin-off of the natural gas businesses to Spectra Energy effective January 2, 2007, the above matters related to Natural Gas Transmission will have no impact on Duke Energy's future consolidated results of operations, cash flows or financial position

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

5. Joint Ownership of Generating and Transmission Facilities

Duke Energy Carolinas, along with North Carolina Municipal Power Agency Number 1, North Carolina Electric Membership Corporation, Piedmont Municipal Power Agency and Saluda River Electric Cooperative, Inc , have joint ownership of Catawba Nuclear Station, which is a facility operated by Duke Energy Carolinas Duke Energy Ohio, Columbus Southern Power Company, and Dayton Power & Light jointly own electric generating units and related transmission facilities in Ohio Duke Energy Ohio and Wabash Valley Power Association, Inc (WVPA) jointly own Vermillion Station Additionally, Duke Energy Indiana is a joint-owner of Gibson Station Unit No 5 with WVPA, and Indiana Municipal Power Agency (IMPA), as well as a joint-owner with WVPA and IMPA of certain Indiana transmission property and local facilities These facilities constitute part of the integrated transmission and distribution systems, which are operated and maintained by Duke Energy Indiana

As of December 31, 2006, Duke Energy's shares in jointly-owned plant or facilities were as follows:

	Ownership Share	Property, Plant, and Equipment	Accumulated Depreciation	Construction Work in Progress
		(in millions)		
Duke Energy Carolinas				
Production:				
Catawba Nuclear Station (Units 1 and 2) [(c)]	12.5%	$ 563	$ 302	$ 10
Duke Energy Ohio				
Production:				
Miami Fort Station (Units 7 and 8) [(b)]	64.0	330	147	197
W.C. Beckjord Station (Unit 6) [(b)]	37.5	46	32	3
J M Stuart Station[(a)(b)]	39 0	420	179	153
Conesville Station (Unit 4)[(a)(b)]	40.0	81	52	28
W M Zimmer Station[(b)]	46 5	1,315	482	10
Killen Station[(a)(b)]	33.0	210	122	44
Vermillion[(b)]	75 0	197	34	—
Transmission	Various	88	47	1
Duke Energy Indiana				
Production:				
Gibson Station (Unit 5) [(c)]	50 05	287	146	6
Transmission and local facilities	94.28	2,740	1,126	—
Duke Energy Kentucky				
Production:				
East Bend Station[(c)]	69 0	423	217	4

(a) Station is not operated by Duke Energy Ohio

(b) Included in Commercial Power segment

(c) Included in U S Franchised Electric and Gas segment

In December 2006, Duke Energy announced an agreement to purchase a portion of Saluda River Electric Cooperative, Inc 's ownership interest in the Catawba Nuclear Station Under the terms of the agreement, Duke Energy will pay approximately $158 million for the additional ownership interest of the Catawba Nuclear Station Following the closing of the transaction, Duke Energy will own approximately 19 percent of the Catawba Nuclear Station This transaction, which is expected to close prior to September 30, 2008, is subject to approval by various state and federal agencies

Duke Energy's share of revenues and operating costs of the above jointly owned generating facilities are included within the corresponding line on the Consolidated Statements of Operations

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

6. Income Taxes

The following details the components of income tax expense:

Income Tax Expense

	For the Years Ended December 31,		
	2006	2005	2004
		(in millions)	
Current income taxes			
Federal	$ 893	$ 845	$ (61)
State	67	138	17
Foreign	154	100	84
Total current income taxes	1,114	1,083	40
Deferred income taxes			
Federal	(248)	174	555
State	(9)	(39)	(119)
Foreign	(2)	74	42
Total deferred income taxes	(259)	209	478
Investment tax credit amortization	(12)	(10)	(11)
Total income tax expense from continuing operations	843	1,282	507
Total income tax expense (benefit) from discontinued operations	(14)	(430)	54
Total income tax benefit from cumulative effect of change in accounting principle	—	(1)	—
Total income tax expense presented in Consolidated Statements of Operations	$ 829	$ 851	$ 561

Earnings from Continuing Operations before Income Taxes

	For the Years Ended December 31,		
	2006	2005	2004
		(in millions)	
Domestic	$ 2,279	$ 3,220	$ 1,295
Foreign	583	591	458
Total earnings from continuing operations before income taxes	$ 2,862	$ 3,811	$ 1,753

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

Reconciliation of Income Tax Expense at the U.S. Federal Statutory Tax Rate to the Actual Tax Expense from Continuing Operations (Statutory Rate Reconciliation)

	For the Years Ended December 31,		
	2006	2005	2004
		(in millions)	
Income tax expense (benefit), computed at the statutory rate of 35%	$ 1,002	$ 1,334	$ 614
State income tax, net of federal income tax effect	38	64	(66)
Tax differential on foreign earnings	(52)	(33)	(34)
Employee stock ownership plan dividends	(29)	(22)	(19)
US tax on repatriation of foreign earnings	—	(2)	36
Other items, net	(116)	(59)	(24)
Total income tax expense from continuing operations	$ 843	$ 1,282	$ 507
Effective tax rate	29.5%	33.6%	28.9%

During 2006, Duke Energy had favorable tax settlements on research and development costs and nuclear decommissioning costs of approximately $30 million, tax benefits related to the impairment of an investment in Bolivia of approximately $25 million and tax credits recognized on synthetic fuel operations of approximately $20 million The reduction in 2006 is reflected in the above table in Other Items, net

During 2005, Duke Energy reorganized various entities and reestimated its liability which enabled it to reduce the $45 million tax liability to $39 million The reduction in 2005 is included in the Statutory Rate Reconciliation as follows: Federal income taxes of $2 million are included in "U S tax on repatriation of foreign earnings" and $4 million of state taxes are included in "State income tax, net of federal income tax effect."

During 2004, Duke Energy recorded a $52 million income tax benefit from the reduction of state and federal income tax reserves based on the resolution in the second quarter of 2004 of several tax issues The $52 million benefit is included in the Statutory Rate Reconciliation as follows: a $39 million state benefit is included in "State income tax, net of federal income tax effect" and a $13 million federal benefit is included in "Other items, net".

During 2004, Duke Energy recorded a $20 million income tax benefit from the change in state tax rates relating to deferred taxes as a result of a reorganization of certain subsidiaries The $20 million benefit is included in "State income tax, net of federal income tax effect" in the Statutory Rate Reconciliation

During 2004, Duke Energy recorded a $45 million income tax expense for the repatriation of foreign earnings which occurred during 2005 related to the American Jobs Creation Act of 2004 The $45 million is included in the Statutory Rate Reconciliation as follows: Federal income taxes of $36 million are included in "US tax on repatriation of foreign earnings," $4 million of state taxes are included in "State income tax, net of federal income tax effect," and $5 million of foreign taxes are included in "Tax differential on foreign earnings "

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

Net Deferred Income Tax Liability Components

	December 31, 2006	December 31, 2005
	(in millions)	
Deferred credits and other liabilities	$ 1,657	$ 1,364
Other	167	60
Total deferred income tax assets	1,824	1,424
Valuation allowance	(20)	(26)
Net deferred income tax assets	1,804	1,398
Investments and other assets	(1,359)	(1,444)
Accelerated depreciation rates	(4,740)	(3,233)
Regulatory assets and deferred debits	(2,244)	(1,692)
Total deferred income tax liabilities	(8,343)	(6,369)
Total net deferred income tax liabilities	$ (6,539)	$ (4,971)

The above amounts have been classified in the Consolidated Balance Sheets as follows

Deferred Tax Liabilities

	December 31, 2006	December 31, 2005
	(in millions)	
Current deferred tax assets, included in other current assets	$ 357	$ 68
Non-current deferred tax assets, included in other investments and other assets	153	254
Current deferred tax liabilities, included in other current liabilities	(46)	(40)
Non-current deferred tax liabilities	(7,003)	(5,253)
Total net deferred income tax liabilities	$ (6,539)	$ (4,971)

As of December 31, 2006, Duke Energy has net operating loss carryforwards of approximately $20 million relating to state income taxes which mostly expire in years 2016 and later

Although the outcome of tax audits is uncertain, management believes that adequate provisions for income and other taxes, such as sales and use, franchise, and property, have been made for potential liabilities resulting from such matters As of December 31, 2006, Duke Energy has total provisions of approximately $190 million for uncertain tax positions, as compared to approximately $150 million as of December 31, 2005, including interest The increase in total provisions since December 31, 2005 is primarily attributable to the merger with Cinergy Management is not aware of any issues for open tax years that upon final resolution are expected to have a material adverse effect on Duke Energy's consolidated results of operations, cash flows or financial position

Valuation allowances have been established for certain foreign and state net operating loss carryforwards that reduce deferred tax assets to an amount that will, more likely than not, be realized The net change in the total valuation allowance is included in "Tax differential on foreign earnings" and "State income tax, net of federal income tax effect" lines of the Statutory Rate Reconciliation

On October 22, 2004, the President of the United States signed the American Jobs Creation Act of 2004 (The Act) The Act provides a deduction for income from qualified domestic production activities, which will be phased in from 2005 to 2010

Under the guidance in FSP No FAS 109-1, which was issued in December 2004, the deduction will be treated as a "special deduction" as described in SFAS No 109 As such, for Duke Energy, the special deduction had no material impact on deferred tax assets and liabilities existing at the enactment date Rather, the impact of this special deduction will be reported in the periods in which the deductions are claimed on the tax returns For the year ended December 31, 2006, Duke Energy did not recognize any benefit relating to the deduction from qualified domestic activities

In addition to the qualified domestic production activities deduction discussed above, the Act creates a temporary incentive for U S corporations to repatriate accumulated income earned abroad by providing an 85 percent dividends received deduction for certain divi -

dends from controlled foreign corporations FSP No FAS 109-2, which was issued in December 2004, states that a company is allowed time beyond the financial reporting period of enactment to evaluate the effect of the Act on its plan for reinvestment or repatriation of foreign earnings, as it applies to the application of SFAS No 109 Although the deduction is subject to a number of limitations and some uncertainty remains as to how to interpret numerous provisions in the Act, Duke Energy recorded a $45 million tax liability at December 31, 2004 based upon Duke Energy's plans that it would repatriate approximately $500 million in extraordinary dividends in 2005 In 2005, Duke Energy repatriated approximately $500 million in extraordinary dividends During this process, Duke Energy reorganized various entities and reduced its liability from $45 million to $39 million There is no remaining liability as of December 31, 2006 and 2005

Deferred income taxes and foreign withholding taxes have not been provided on the remaining undistributed earnings of Duke Energy's foreign subsidiaries as such amounts are deemed to be permanently reinvested The cumulative undistributed earnings as of December 31, 2006 on which Duke Energy has not provided deferred income taxes and foreign withholding taxes, is approximately $420 million

7. Asset Retirement Obligations

In June 2001, the FASB issued SFAS No 143, which was adopted by Duke Energy on January 1, 2003 and addresses financial accounting and reporting for legal obligations associated with the retirement of tangible long-lived assets and the related asset retirement costs The standard applies to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or normal use of the asset SFAS No 143 requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred, if a reasonable estimate of fair value can be made The fair value of the liability is added to the carrying amount of the associated asset This additional carrying amount is then depreciated over the life of the asset The liability increases due to the passage of time based on the time value of money until the obligation is settled Subsequent to the initial recognition, the liability is adjusted for any revisions to the expected value of the retirement obligation (with corresponding adjustments to property, plant, and equipment), and for accretion of the liability due to the passage of time Additional depreciation expense is recorded prospectively for any property, plant and equipment increases

Asset retirement obligations at Duke Energy relate primarily to the decommissioning of nuclear power facilities, the retirement of certain gathering pipelines and processing facilities, obligations related to right-of-way agreements, asbestos removal and contractual leases for land use In accordance with SFAS No 143, Duke Energy identified certain assets that have an indeterminate life, and thus the fair value of the retirement obligation is not reasonably estimable These assets included on-shore and some off-shore pipelines, certain processing plants and distribution facilities and some gas-fired power plants A liability for these asset retirement obligations will be recorded when a fair value is determinable

Upon adoption of SFAS No 143, Duke Energy's regulated electric and regulated natural gas operations classified removal costs for property that does not have an associated legal retirement obligation as a regulatory liability, in accordance with regulatory treatment under SFAS No 71 Duke Energy does not accrue the estimated cost of removal when no legal obligation associated with retirement or removal exists for any of our non-regulated assets (including Duke Energy Ohio's generation assets) The total amount of removal costs included in Other Deferred Credits and Other Liabilities on the Consolidated Balance Sheets was $2,345 million and $1,670 million as of December 31, 2006 and 2005, respectively, which consisted of $1,954 million and $1,320 million, respectively, related to regulated electric operations and $391 million and $350 million, respectively, related to regulated natural gas operations

The adoption of SFAS No 143 had no impact on the income of the regulated electric operations, as the effects were offset by the establishment of regulatory assets and liabilities pursuant to SFAS No 71 as Duke Energy received approval from both the NCUC and PSCSC to defer all cumulative and future income statement impacts related to SFAS No 143

In March 2005, the FASB issued FIN 47 As a result of the adoption of FIN 47 in 2005, an increase in total assets of $31 million was recorded, consisting of an increase in regulatory assets of $24 million, an increase in net property, plant and equipment of $7 million and an increase in ARO liabilities of approximately $35 million The adoption of FIN 47 had no impact on the income of the regulated electric operations, as the effects were offset by the establishment of regulatory assets and liabilities pursuant to SFAS No 71 For obligations related to other operations, a net-of-tax cumulative effect adjustment of approximately $4 million was recorded in the fourth quarter of 2005 as a reduction in earnings (see Note 1)

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

The pro forma effects of adopting FIN 47, including the impact on the balance sheet, net income and related basic and diluted earnings per share, are not presented due to the immaterial impact.

The asset retirement obligation is adjusted each period for any liabilities incurred or settled during the period, accretion expense and any revisions made to the estimated cash flows.

Reconciliation of Asset Retirement Obligation Liability

	Years Ended December 31,	
	2006	2005
	(in millions)	
Balance as of January 1,	$ 2,058	$ 1,926
Liabilities incurred due to new acquisitions[a]	59	—
Liabilities settled	(7)	(46)
Accretion expense	143	131
Revisions in estimated cash flows	48	12
Adoption of FIN 47	—	35
Balance as of December 31,	$ 2,301	$ 2,058

(a) Primarily represents Duke Energy's acquisition of Cinergy in April 2006

Accretion expense for the years ended December 31, 2006 and 2005 included approximately $140 million and $130 million, respectively, related to Duke Energy's regulated electric operations which has been deferred as regulatory assets and liabilities in accordance with SFAS No 71, as discussed above The fair value of assets legally restricted for the purpose of settling asset retirement obligations associated with nuclear decommissioning was $1,421 million as of December 31, 2006 and $1,194 million as of December 31, 2005

Nuclear Decommissioning Costs. Pursuant to an order issued by the NCUC on February 5, 2004, Duke Energy was required to contribute amounts reserved for non-contaminated costs of decommissioning to the NDTF over a ten-year period In April 2004, Duke Energy contributed its entire reserve of $262 million in cash to the NDTF This contribution is presented in the Consolidated Statements of Cash Flows in Purchases of Available-For-Sale Securities within Cash Flows from Investing Activities

In 2005, the NCUC and PSCSC approved a $48 million annual amount for contributions and expense levels for decommissioning In each of the years ended December 31, 2006 and 2005, Duke Energy expensed approximately $48 million and contributed cash of approximately $48 to the NDTF for decommissioning costs These amounts are presented in the Consolidated Statements of Cash Flows in Purchases of Available-For-Sale Securities within Cash Flows from Investing Activities In both 2006 and 2005, $48 million was contributed entirely to the funds reserved for contaminated costs Contributions were discontinued to the funds reserved for non-contaminated costs since the current estimates indicate existing funds to be sufficient to cover projected future costs The balance of the external funds was $1,775 million as of December 31, 2006 and $1,504 million as of December 31, 2005 These amounts are reflected in the Consolidated Balance Sheets as Nuclear Decommissioning Trust Funds (asset)

Estimated site-specific nuclear decommissioning costs, including the cost of decommissioning plant components not subject to radioactive contamination, total approximately $2 3 billion in 2003 dollars, based on a decommissioning study completed in 2004 This includes costs related to Duke Energy's 12 5% ownership in the Catawba Nuclear Station The other joint owners of the Catawba Nuclear Station are responsible for decommissioning costs related to their ownership interests in the station Both the NCUC and the PSCSC have allowed Duke Energy to recover estimated decommissioning costs through retail rates over the expected remaining service periods of Duke Energy's nuclear stations Management believes that the decommissioning costs being recovered through rates, when coupled with expected fund earnings, are sufficient to provide for the cost of decommissioning

The operating licenses for Duke Energy's nuclear units are subject to extension In December 2003, Duke Energy was granted renewed operating licenses for the Catawba and McGuire Nuclear Stations until 2041 and 2043 (license expirations vary by nuclear unit) In 2000, Duke Energy was granted a license renewal for the Oconee Nuclear Station until 2033 and 2034 (license expirations vary by nuclear unit)

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

Current Operating Licenses for Duke Energy's Nuclear Units

Unit	Expiration Year
McGuire 1	2041
McGuire 2	2043
Catawba 1	2043
Catawba 2	2043
Oconee 1 and 2	2033
Oconee 3	2034

A provision in the Energy Policy Act of 1992 established a fund for the decontamination and decommissioning of the DOE's uranium enrichment plants (the D&D Fund) Licensees are subject to an annual assessment for 15 years based on their pro rata share of past enrichment services. The annual assessment is recorded in the Consolidated Statements of Operations as Fuel Used in Electric Generation and Purchased Power Duke Energy has paid $152 million into the D&D Fund, including $12 million during 2006 and $11 million during each of 2005 and 2004 There is no remaining liability and regulatory assets as of December 31, 2006 The liability and regulatory assets of $12 million as of December 31, 2005 are reflected in the Consolidated Balance Sheets as Deferred Credits and Other Liabilities, and Regulatory Assets and Deferred Debits, respectively

8. Risk Management and Hedging Activities, Credit Risk, and Financial Instruments

Duke Energy is exposed to the impact of market fluctuations in the prices of electricity, coal, natural gas and other energy-related products marketed and purchased as a result of its ownership of energy related assets Exposure to interest rate risk exists as a result of the issuance of variable and fixed rate debt and commercial paper Duke Energy is exposed to foreign currency risk from investments in international affiliate businesses owned and operated in foreign countries and from certain commodity-related transactions within domestic operations Duke Energy employs established policies and procedures to manage its risks associated with these market fluctuations using various commodity and financial derivative instruments, including swaps, futures, forwards, options and swaptions

Duke Energy's Derivative Portfolio Carrying Value as of December 31, 2006

Asset/(Liability)	Maturity in 2007	Maturity in 2008	Maturity in 2009	Maturity in 2010 and Thereafter	Total Carrying Value
			(in millions)		
Hedging	$ 4	$ —	$ 17	$ (8)	$ 13
Trading	2	—	—	—	2
Undesignated	(33)	(5)	2	4	(32)
Total	$ (27)	$ (5)	$ 19	$ (4)	$ (17)

The amounts in the table above represent the combination of amounts presented as assets and (liabilities) for unrealized gains and losses on mark-to-market and hedging transactions on Duke Energy's Consolidated Balance Sheets, excluding approximately $39 million of derivative assets and $39 million of derivative liabilities presented as assets and liabilities held for sale at December 31, 2006

During the third quarter of 2005, Duke Energy's Board of Directors authorized and directed management to execute the sale or disposition of substantially all of DENA's remaining assets and contracts outside the Midwestern United States, approximately 6,100 megawatts of power generation, and certain contractual positions related to the Midwestern assets (see Note 13) As a result, Duke Energy recognized a pre-tax loss of approximately $1 9 billion in the third quarter of 2005 for the disqualification of its power and gas forward sales contracts previously designated under the normal purchases normal sales exception This loss was partially offset by the recognition of a pre-tax gain of approximately $1 2 billion for the discontinuance of hedge accounting for natural gas and power cash flow hedges. Duke Energy retained the Midwestern generation assets of DENA, representing approximately 3,600 megawatts of power generation, and combined the assets with Cinergy's commercial operations subsequent to the merger with Cinergy on April 3, 2006 (see Note 1 and Note 2 for further details on the completed Cinergy merger) Derivative activity associated with these combined assets is reported in Commercial Power for segment reporting purposes for all periods presented

As a result of the transfer of 19 7% interest in DEFS to ConocoPhillips and the third quarter 2005 deconsolidation of its investment in DEFS (see Note 2), Duke Energy discontinued hedge accounting for certain contracts held by Duke Energy related to Field Services' commodity price risk, which were previously accounted for as cash flow hedges These contracts were originally entered into as hedges of forecasted future sales by Field Services, and have been retained as undesignated derivatives Since discontinuance of hedge accounting, these contracts have been marked-to-market in the Consolidated Statements of Operations As a result, approximately $19 million and $314 million of realized and unrealized pre-tax losses related to these contracts were recognized in earnings by Duke Energy for the years ended December 31, 2006 and December 31, 2005, respectively All the 2006 charges have been classified in the accompanying Consolidated Statements of Operations as a component of Other Income and Expenses The 2005 charges were classified in the accompanying Consolidated Statements of Operations for the year ended as follows: upon the discontinuance of hedge accounting approximately $120 million of pre-tax losses were recognized as a component of Impairments and Other Charges while approximately $130 million of losses recognized subsequent to the discontinuance of hedge accounting prior to the deconsolidation of DEFS were recognized as a component of Non-Regulated Electric, Natural Gas, Natural Gas Liquids, and Other Revenues and $64 million of losses recognized subsequent to discontinuance of hedge accounting after the deconsolidation of DEFS were recognized as a component of Other Income and Expenses Cash settlements on these contracts since the deconsolidation of DEFS on July 1, 2005 of approximately $163 million and $133 million are classified as a component of net cash used in investing activities in the accompanying Consolidated Statements of Cash Flows for the years ended December 31, 2006 and December 31, 2005, respectively.

Commodity Cash Flow Hedges. Some Duke Energy subsidiaries are exposed to market fluctuations in the prices of various commodities related to their ongoing power generating and natural gas gathering, distribution, processing and marketing activities Duke Energy closely monitors the potential impacts of commodity price changes and, where appropriate, enters into contracts to protect margins for a portion of future sales and generation revenues and fuel expenses Duke Energy uses commodity instruments, such as swaps, futures, forwards and options, as cash flow hedges for electricity, natural gas and natural gas liquid transactions Duke Energy is hedging exposures to the price variability of these commodities for a maximum of 1 year

The ineffective portion of commodity cash flow hedges resulted in a pre-tax gain of $5 million in 2006 and is reported primarily in Non-regulated electric, natural gas, natural gas liquids, and other in the Consolidated Statements of Operations, a pre-tax loss of $12 million in 2005 and a pre-tax gain of $3 million in 2004, both reported primarily in (Loss) Income From Discontinued Operations, net of tax in the Consolidated Statements of Operations The amount recognized for transactions that no longer qualified as cash flow hedges, which is classified in (Loss) Income From Discontinued Operations, net of tax in the Consolidated Statements of Operations, was a loss of approximately $67 million in 2006, a gain of approximately $1 2 billion in 2005 and was not material in 2004

As of December 31, 2006, $2 million of pre-tax deferred net gains on derivative instruments related to commodity cash flow hedges were accumulated on the Consolidated Balance Sheets in a separate component of stockholders' equity, in AOCI, and are expected to be recognized in earnings during the next twelve months as the hedged transactions occur However, due to the volatility of the commodities markets, the corresponding value in AOCI will likely change prior to its reclassification into earnings

Commodity Fair Value Hedges Some Duke Energy subsidiaries are exposed to changes in the fair value of some unrecognized firm commitments to sell generated power or natural gas due to market fluctuations in the underlying commodity prices Duke Energy actively evaluates changes in the fair value of such unrecognized firm commitments due to commodity price changes and, where appropriate, uses various instruments to hedge its market risk These commodity instruments, such as swaps, futures and forwards, serve as fair value hedges for the firm commitments associated with generated power The ineffective portion of commodity fair value hedges resulted in a pre-tax gain of $7 million in 2006, a pre-tax loss of $4 million in 2005 and was not material in 2004, and is reported primarily in (Loss) Income From Discontinued Operations, net of tax on the Consolidated Statements of Operations

Normal Purchases and Normal Sales Exception. Duke Energy has applied the normal purchases and normal sales scope exception, as provided in SFAS No 133, interpreted by Derivative Implementation Group Issue C15, "Scope Exceptions: Normal Purchases and Normal Sales Exception for Option-Type Contracts and Forward Contracts in Electricity," and amended by SFAS No 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities," to certain contracts involving the purchase and sale of electricity at fixed prices in future periods These contracts, which relate primarily to the delivery of electricity over the next 8 years, are not included in the table above As discussed above, during 2005, Duke Energy recognized a pre-tax loss of approximately $1 9 billion for the disqualification of its power and gas forward sales contracts

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

Certain forward power contracts related to DENA's Southeast Plants and the deferred plants had been primarily designated as normal purchases and sales in accordance with SFAS No 133. In addition, certain forward gas contracts related to the long-lived assets had been designated as cash flow hedges in accordance with SFAS No. 133 As a result of the change in management intent for the long- lived assets, the related forward power and gas contracts were de-designated as normal purchases and sales and hedges. The amount recognized for transactions that no longer qualified as hedged firm commitments was not material in 2006 and 2004

Interest Rate (Fair Value or Cash Flow) Hedges. Changes in interest rates expose Duke Energy to risk as a result of its issuance of variable and fixed rate debt and commercial paper Duke Energy manages its interest rate exposure by limiting its variable-rate exposures to percentages of total capitalization and by monitoring the effects of market changes in interest rates. Duke Energy also enters into financial derivative instruments, including, but not limited to, interest rate swaps, swaptions and U S Treasury lock agreements to manage and mitigate interest rate risk exposure. Duke Energy's existing interest rate derivative instruments and related ineffectiveness were not material to its consolidated results of operations, cash flows or financial position in 2006, 2005, and 2004

Foreign Currency (Fair Value, Net Investment or Cash Flow) Hedges. Duke Energy is exposed to foreign currency risk from investments in international affiliate businesses owned and operated in foreign countries and from certain commodity-related transactions within domestic operations To mitigate risks associated with foreign currency fluctuations, contracts may be denominated in or indexed to the U.S. dollar and/or local inflation rates, ~~or investments may be naturally hedged through debt denominated or issued in the foreign currency. Duke Energy may~~ also use foreign currency derivatives, where possible, to manage its risk related to foreign currency fluctuations There was no recognition, a net loss of $1 million and a net loss of $43 million included in the cumulative translation adjustment for hedges of net investments in foreign operations, during 2006, 2005, and 2004, respectively To monitor its currency exchange rate risks, Duke Energy uses sensitivity analysis, which measures the impact of devaluation of foreign currencies.

During the first quarter of 2005, Duke Energy settled certain hedges which were documented and designated as net investment hedges of the investment in Westcoast Energy, Inc (Westcoast) on their scheduled maturity and paid approximately $162 million These settlements are classified as a component of net cash used in investing activities in the accompanying Consolidated Statements of Cash Flows Losses recognized on this net investment hedge have been classified in AOCI as a component of foreign currency adjustments and will not be recognized in earnings unless the complete or substantially complete liquidation of Duke Energy's investment in Westcoast occurs.

Other Derivative Contracts. *Trading.* Duke Energy has been exposed to the impact of market fluctuations in the prices of natural gas, electricity and other energy-related products marketed and purchased as a result of proprietary trading activities During 2003, Duke Energy prospectively discontinued proprietary trading As a result of the Cinergy merger, Duke Energy acquired natural gas and power marketing and trading operations, conducted primarily through CMT. the results of which have been reflected in Income (Loss) from Discontinued Operations, net of tax, from the date of the Cinergy acquisition to the date of sale In October 2006. the CMT sale transaction was completed and Duke Energy entered into a series of Total Return Swaps (TRS) with Fortis (see Note 13) As of December 31, 2006, the remaining CMT trading contract assets and liabilities and offsetting TRS were classified as Assets Held for Sale in the Consolidated Balance Sheets

Undesignated In addition, Duke Energy uses derivative contracts to manage the market risk exposures that arise from energy supply, structured origination, marketing, risk management, and commercial optimization services to large energy customers, energy aggregators and other wholesale companies, and to manage interest rate and foreign currency exposures This category includes changes in fair value for derivatives that no longer qualify for the normal purchase and normal sales scope exception and disqualified hedge contracts, unless the derivative contract is subsequently re-designated as a hedge The contracts in this category as of December 31, 2006 are primarily associated with forward power sales and coal purchases for the Commercial Power operations and remaining DENA exit activity announced in 2005 (see Note 13) As of December 31, 2005, this category primarily included disqualified hedges related to the DENA Southeast Plants, hedges related to the partially completed plants which were disqualified in 2003 and certain contracts held by Duke Energy related to Field Services commodity price risk Duke Energy's exposure to price risk is influenced by a number of factors, including contract size, length, market liquidity, location and unique or specific contract terms.

In connection with the Barclays Bank PLC (Barclays) transaction discussed in Note 13, Duke Energy entered into a series of TRS with Barclays, which are accounted for as mark-to-market derivatives The TRS offsets the net fair value of the contracts being sold to Barclays The fair value of the TRS as of December 31, 2006 is an asset of approximately $56 million, which offsets the net fair value of the underlying contracts, which is a liability of approximately $56 million The TRS will be cancelled as the underlying contracts are transferred to Barclays

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

Credit Risk. Duke Energy's principal customers for power and natural gas marketing and transportation services are industrial end-users, marketers, local distribution companies and utilities located throughout the U S , Canada and Latin America Duke Energy has concentrations of receivables from natural gas and electric utilities and their affiliates, as well as industrial customers and marketers throughout these regions These concentrations of customers may affect Duke Energy's overall credit risk in that risk factors can negatively impact the credit quality of the entire sector Where exposed to credit risk, Duke Energy analyzes the counterparties' financial condition prior to entering into an agreement, establishes credit limits and monitors the appropriateness of those limits on an ongoing basis

Duke Energy's industry has historically operated under negotiated credit lines for physical delivery contracts Duke Energy frequently uses master collateral agreements to mitigate certain credit exposures, primarily in its trading and marketing and risk management operations The collateral agreements provide for a counterparty to post cash or letters of credit to the exposed party for exposure in excess of an established threshold The threshold amount represents an unsecured credit limit, determined in accordance with the corporate credit policy Collateral agreements also provide that the inability to post collateral is sufficient cause to terminate contracts and liquidate all positions

Duke Energy also obtains cash or letters of credit from customers to provide credit support outside of collateral agreements, where appropriate, based on its financial analysis of the customer and the regulatory or contractual terms and conditions applicable to each transaction

Collateral amounts held or posted may be fixed or may vary depending on the terms of the collateral agreement and the nature of the underlying exposure and generally cover trading, normal purchases and normal sales, hedging contracts, and optimization contracts outstanding Duke Energy may be required to return certain held collateral and post additional collateral should price movements adversely impact the value of open contracts or positions In many cases, Duke Energy's and its counterparties' publicly disclosed credit ratings impact the amounts of additional collateral to be posted Likewise, downgrades in credit ratings of counterparties could require counterparties to post additional collateral to Duke Energy and its affiliates

The change in market value of New York Mercantile Exchange (NYMEX)-traded futures and options contracts requires daily cash settlement in margin accounts with brokers

Included in Other Current Assets in the Consolidated Balance Sheets as of December 31, 2006 and December 31, 2005 are collateral assets of approximately $92 million and $1,279 million, respectively, which represents cash collateral posted by Duke Energy with other third parties This decrease in cash collateral posted by Duke Energy is primarily due the sale and wind-down of trading operations Included in Other Current Liabilities and Other Deferred Credits and Other Liabilities in the Consolidated Balance Sheets as of December 31, 2006 and December 31, 2005 are collateral liabilities of approximately $239 million and $664 million, respectively, which represents cash collateral posted by other third parties to Duke Energy In connection with the sale to Barclays of contracts related to DENA's energy marketing and management activities, Barclays provided DENA cash equal to the net cash collateral posted by DENA under the contracts Net cash collateral received by Duke Energy from Barclays in January 2006 was approximately $540 million based on current market prices of the contracts (see Note 13)

Financial Instruments. The fair value of financial instruments, excluding derivatives included elsewhere in this Note and in Note 13, is summarized in the following table Judgment is required in interpreting market data to develop the estimates of fair value Accordingly, the estimates determined as of December 31, 2006 and 2005, are not necessarily indicative of the amounts Duke Energy could have realized in current markets

Financial Instruments

	As of December 31,			
	2006		2005	
	Book Value	Approximate Fair Value	Book Value	Approximate Fair Value
	(in millions)			
Long-term debt[(a)]	$ 19,723	$ 20,765	$ 15,947	$ 17,014
Long-term SFAS 115 securities	1,946	1,946	1,735	1,735

(a) Includes current maturities

The fair value of cash and cash equivalents, short-term investments, accounts and notes receivable, accounts payable and commercial paper are not materially different from their carrying amounts because of the short-term nature of these instruments or because the stated rates approximate market rates

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

9. Marketable Securities

Short-term investments. At December 31, 2006 and 2005 Duke Energy had $1,514 million and $632 million, respectively, of short-term investments consisting primarily of highly liquid tax-exempt debt securities These instruments are classified as available-for-sale securities under SFAS No 115 as management does not intend to hold them to maturity nor are they bought and sold with the objective of generating profits on short-term differences in price The carrying value of these instruments approximates their fair value as they contain floating rates of interest During 2006, Duke Energy purchased approximately $31,521 million and received proceeds on sale of approximately $30,692 million of short-term investments During 2005, Duke Energy purchased approximately $38,535 million and received proceeds on sale of approximately $38,386 million of short-term investments During 2004, Duke Energy purchased approximately $63,879 million and received proceeds on sale of approximately $63,323 million of short-term investments The weighted-average maturity of these debt securities is less than 1 year

During 2006, Duke Energy's Natural Gas Transmission business unit received shares of stock as consideration for settlement of a customer's transportation contract The market value of the equity securities, determined by quoted market prices on the date of receipt, of approximately $28 million is reflected in Gains (Losses) on Sales of Other Assets and Other, net in the Consolidated Statements of Operations for the year ended December 31, 2006 Subsequent to receipt, these securities were accounted for under SFAS No 115 as trading securities During the year ended December 31, 2006, these securities were sold and an additional gain of approximately $1 million was recognized in Other Income and Expenses, net in the Consolidated Statements of Operations for the year ended December 31, 2006

During 2006, Duke Energy recognized an approximate $51 million pre-tax gain on the sale of available-for-sale securities that were included in Assets held for sale on the Consolidated Balance Sheets This gain was recorded as a component of (Loss) Income from Discontinued Operations in Other

Other Long-term investments Duke Energy also invests in debt and equity securities that are held in the NDTF (see Note 7 for further information on the nuclear decommissioning trust funds) and the captive insurance investment portfolio that are classified as available-for-sale under SFAS No 115 and therefore are carried at estimated fair value based on quoted market prices These investments are classified as long-term as management does not intend to use them in current operations The NDTF is managed by independent investment managers with discretion to buy, sell and invest pursuant to the objectives set forth by the trust agreement As of December 31, 2006 Duke Energy's NDTF ($1,775 million and $1,504 million at December 31, 2006 and 2005, respectively) consists of approximately 70% equity securities, 24% debt securities, and 6% cash and cash equivalents with a weighted-average maturity of the debt securities of approximately 13 years Duke Energy's captive insurance investment portfolio ($171 million and $203 million at December 31, 2006 and 2005, respectively) consists of approximately 88% debt securities and 12% equity securities with a weighted-average maturity of the debt securities of approximately 21 years, as of December 31, 2006 The cost of securities sold is determined using the specific identification method During 2006, Duke Energy purchased approximately $1,915 million and received proceeds on sales of approximately $1,904 million on other long-term investments During 2005, Duke Energy purchased approximately $1,782 million and received proceeds on sales of approximately $1,745 million on other long-term investments During 2004, Duke Energy purchased approximately $2,050 million and received proceeds on sales of approximately $1,775 million on other long-term investments Most of these purchases and sales relate to the NDTF

The estimated fair values of short-term and long-term investments classified as available-for-sale are as follows (in millions):

	As of December 31,					
	2006			2005		
	Gross Unrealized Holding Gains	Gross Unrealized Holding Losses	Estimated Fair Value	Gross Unrealized Holding Gains	Gross Unrealized Holding Losses	Estimated Fair Value
Short-term Investments	$ —	$ —	$ 1,514	$ —	$ —	$ 632
Total short-term investments	$ —	$ —	$ 1,514	$ —	$ —	$ 632
Equity Securities	$ 467	$ —	$ 1,268	$ 333	$ —	$ 1,098
Corporate Debt Securities	1	1	85	—	1	61
Municipal Bonds	1	—	236	1	—	203
U S Government Bonds	7	—	159	13	—	230
Other	1	1	198	—	1	143
Total long-term investments	$ 477	$ 2	$ 1,946	$ 347	$ 2	$ 1,735

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

Approximately $13 million and $21 million of losses are excluded from the above table as of December 31, 2006 and 2005, respectively, which relate to available-for-sale securities held in the NDTF Pursuant to an order from the NCUC, Duke Energy defers as a regulatory asset or regulatory liability all gains and losses associated with investments in the NDTF As Duke Energy has limited oversight over the day-to-day management of the NDTF investments, all losses during the years ended December 31, 2006 and 2005 related to holdings of the NDTF have been recognized as a regulatory asset.

For the years ended December 31, 2006, 2005, and 2004 gains of approximately $57 million (including $51 million reclassified to (Loss) Income from Discontinued Operations, net of tax), $3 million and $3 million, respectively, were reclassified out of AOCI into earnings

Duke Energy contributed approximately $48 million in 2006, $48 million in 2005, and $329 million in 2004 to the NDTF These contributions are presented in Purchases of available-for-sale securities within Cash Flows From Investing Activities on the Consolidated Statements of Cash Flows At December 31, 2006 and 2005, gross unrealized holding gains related to the NDTF amounted to $472 million and $316 million, respectively

10. Goodwill and Intangible Assets

Duke Energy evaluates the impairment of goodwill under the guidance of SFAS No. 142. As a result of the annual impairment tests required by SFAS No. 142, no charge for the impairment of goodwill was recorded in 2006 directly related to these tests As discussed further in Note 2, in April 2006, Duke Energy and Cinergy consummated the previously announced merger, which resulted in Duke Energy recording goodwill and intangible assets of approximately $5 6 billion The following table shows the components of goodwill at December 31, 2006:

Changes in the Carrying Amount of Goodwill

	Balance December 31, 2005	Acquisitions[a]	Other[b][e]	Balance December 31, 2006
		(in millions)		
U.S. Franchised Electric and Gas	$—	$3,500	$—	$ 3,500
Natural Gas Transmission	3,512	—	11	3,523
Commercial Power	—	1,020	(135)	885
International Energy	256	—	11	267
Crescent[c]	7	—	(7)	—
Total consolidated	$3,775	$4,520	$(120)	$8,175

	Balance December 31, 2004	Acquisitions	Other[d][e]	Balance December 31, 2005
Natural Gas Transmission	$3,416	$—	$96	$3,512
Field Services	480	—	(480)	—
International Energy	245	—	11	256
Crescent	7	—	—	7
Total consolidated	$4,148	$—	$(373)	$3,775

(a) Goodwill recorded as of December 31, 2006 resulting from Duke Energy's merger with Cinergy is $4,385 million

(b) Primarily relates to foreign currency translation and approximately $135 million of goodwill allocated to the disposition of CMT (see Note 13).

(c) Reduction in goodwill at December 31, 2006 reflects the deconsolidation of Crescent in September 2006 (see Note 2).

(d) As a result of the deconsolidation of DEFS in July 2005 goodwill decreased by a net amount of $462 million, which includes the effects of an $18 million transfer of goodwill between Field Services and Natural Gas Transmission as a result of the transfer of Canadian assets in connection with the DEFS disposition transaction (see Note 2)

(e) Except as noted in (b), (c) and (d), other amounts consist primarily of foreign currency translation.

Intangible Assets

In April 2006, in connection with the merger with Cinergy, Duke Energy recorded gross intangible assets of approximately $1,091 million, primarily relating to approximately $712 million of emission allowances, approximately $295 million of gas, coal and power contracts and approximately $84 million of other intangible assets

The carrying amount and accumulated amortization of intangible assets as of December 31, 2006 and December 31, 2005 are as follows:

	December 31, 2006	December 31, 2005	Weighted Average Life
	(in millions)		
Emission allowances	$ 587	$ 24	(a)
Gas, coal and power contracts	322	23	(b)
Other	57	23	25
Total gross carrying amount	966	70	
Accumulated amortization—gas, coal and power contracts	(56)	(1)	
Accumulated amortization—other	(5)	(4)	
Total accumulated amortization	(61)	(5)	
Total intangible assets, net	$ 905	$ 65	

(a) Emission allowances do not have a contractual term or expiration date

(b) Of this balance, as of December 31, 2006, approximately $115 million will be amortized on a consumption basis and does not have a definitive life, approximately $155 million will be amortized on a straight line basis over 20 years, and the remaining balance of approximately $52 million will be amortized on a straight line basis over a weighted average life of approximately 14 years

Emission allowances sold or consumed during the years ended December 31, 2006, 2005 and 2004 were $428 million, $8 million and $6 million, respectively

Amortization expense for intangible assets for the years ended December 31, 2006, 2005 and 2004 was approximately $48 million, $1 million and $1 million, respectively

The table below shows the expected amortization expense for the next five years for intangible assets as of December 31, 2006 The expected amortization expense includes estimates of emission allowances consumption and estimates of consumption of commodities such as gas and coal under existing contracts The amortization amounts discussed below are estimates Actual amounts may differ from these estimates due to such factors as changes in consumption patterns, sales or impairments of emission allowances or other intangible assets, additional intangible acquisitions and other events

	2007	2008	2009	2010	2011
			(in millions)		
Amortization expense	$ 391	$ 167	$ 143	$ 102	$ 87

In April 2006, Duke Energy recorded an intangible liability in connection with the merger with Cinergy amounting to approximately $113 million associated with the MBSSO in Ohio that will be recognized in earnings over the remaining regulatory period, which ends on December 31, 2008 The carrying amount of this intangible liability was approximately $95 million at December 31, 2006 Amortization expense related to the MBSSO is estimated to amount to approximately $27 million of income in 2007 and $68 million of income in 2008 Duke Energy also recorded approximately $56 million of intangible liabilities associated with other power sale contracts in connection with the merger with Cinergy The carrying amount of this intangible liability was approximately $39 million at December 31, 2006 This balance will be amortized to income as follows: approximately $17 million in 2007, approximately $6 million in each of the years 2008 through 2010, and approximately $4 million in 2011

11. Investments in Unconsolidated Affiliates and Related Party Transactions

Investments in domestic and international affiliates that are not controlled by Duke Energy, but over which it has significant influence, are accounted for using the equity method Duke Energy received distributions of $893 million in 2006 from those investments Of these distributions, $741 million are included in Other, assets within Cash Flows from Operating Activities on the accompanying Consolidated

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

Statements of Cash Flows and $152 million are included in Distributions from Equity Investments within Cash Flows from Investing Activities on the accompanying Consolidated Statements of Cash Flows Duke Energy received distributions of $856 million in 2005 Of these distributions, $473 million are included in Other, assets within Cash Flows from Operating Activities on the accompanying Consolidated Statements of Cash Flows and $383 million are included in Distributions from Equity Investments within Cash Flows from Investing Activities on the accompanying Consolidated Statements of Cash Flows Duke Energy received distributions of $139 million in 2004, which are included in Other, assets within Cash Flows from Operating Activities on the accompanying Consolidated Statements of Cash Flows Duke Energy's share of net earnings from these unconsolidated affiliates is reflected in the Consolidated Statements of Operations as Equity in Earnings of Unconsolidated Affiliates (See Note 2 for 2006 dispositions)

As of December 31, 2006 and 2005, the carrying amount of investments in affiliates approximated the amount of underlying equity in net assets

Natural Gas Transmission As of December 31, 2006, investments primarily included a 50% interest in Gulfstream Natural Gas System, LLC (Gulfstream) Gulfstream is an interstate natural gas pipeline that extends from Mississippi and Alabama across the Gulf of Mexico to Florida Although Duke Energy owns a significant portion of Gulfstream, it is not consolidated as Duke Energy does not hold a majority of voting control or have the ability to exercise control over Gulfstream

Field Services In July 2005, Duke Energy completed the transfer of a 19 7% interest in DEFS to ConocoPhillips, Duke Energy's co-equity owner in DEFS, which reduced Duke Energy's ~~ownership interest in DEFS from 69 7% to 50% (the DEFS disposition transactions) and resulted in Duke Energy and ConocoPhillips becoming equal 50% owners in DEFS. As a result of the~~ DEFS disposition transaction, Duke Energy deconsolidated its investment in DEFS which has subsequently been accounted for as an investment utilizing the equity method of accounting (see Note 2). Additionally, in February 2005, DEFS sold its wholly owned subsidiary TEPPCO GP, which is the general partner of TEPPCO LP, for approximately $1 1 billion and Duke Energy sold its limited partner interest in TEPPCO LP for approximately $100 million, in each case to Enterprise GP Holdings LP, an unrelated third party These transactions resulted in pre-tax gains of approximately $1 8 billion For the three months ended March 31, 2005, TEPPCO LP had operating revenues of approximately $1,524 million, operating expenses of approximately $1,463 million, operating income of approximately $61 2 million, income from continuing operations of approximately $46 3 million, and net income of approximately $47 4 million

Commercial Power As of December 31, 2006, investments primarily included a 50% interest in South Houston Green Power, L P (Green Power) Green Power is a cogeneration facility containing three combustion turbines in Texas City, Texas Although Duke Energy owns a significant portion of Green Power, it is not consolidated as Duke Energy does not hold a majority voting control or have the ability to exercise control over Green Power

International Energy As of December 31, 2006, investments primarily included a 25% indirect interest in NMC, which owns and operates a methanol and MTBE business in Jubail, Saudi Arabia International Energy also has a 50% ownership in Campeche, a natural gas compression facility in the Cantarell oil field in the Gulf of Mexico and a 25% indirect interest in Attiki, a natural gas distributor in Athens, Greece

Campeche project revenues are generated from the gas compression services agreement (GCSA) with the Mexican national oil company (PEMEX) The original five year GCSA expired in November 2006 and a nine month extension was executed in October 2006 The facility ownership will transfer to PEMEX in August 2007 See Note 12 for a discussion of the impairment recognized on the Campeche investment

Crescent In September 2006, Duke Energy deconsolidated its investment in Crescent JV as a result of a reduction in ownership and subsequently has accounted for the investment using the equity method of accounting

Other As of December 31, 2006 investments primarily includes Cinergy's telecom investments As of December 31, 2005, investments primarily included a 50% interest in Southwest Power Partners, LLC Southwest Power Partners, LLC is a gas-fired combined-cycle facility (Griffith Energy) in Arizona that serves markets in Arizona, Nevada and California Although Duke Energy owns a significant portion of this investment, it is not consolidated as it does not hold a majority of voting control or have the ability to exercise control over this investment Southwest Power Partners, LLC was included in DENA's Western United States generation assets that were sold to LS Power during 2006 (see Note 13) As a result, the investment was classified as Assets Held for Sale in the Consolidated Balance Sheets as of December 31, 2005 and earnings and losses from this investment are classified as (Loss) Income from Discontinued Operations, net of tax in the accompanying Consolidated Statements of Operations

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

Investments in Unconsolidated Affiliates

	As of:					
	December 31, 2006			December 31, 2005		
	Domestic	International	Total	Domestic	International	Total
	(in millions)					
U.S. Franchised Electric and Gas	$ 2	$ —	$ 2	$ 2	$ —	$ 2
Natural Gas Transmission	434	18	452	428	20	448
Field Services[a]	1,166	—	1,166	1,290	—	1,290
Commercial Power	223	—	223	—	—	—
International Energy	—	165	165	—	155	155
Crescent[b]	180	—	180	17	—	17
Other	104	13	117	14	7	21
Total	$ 2,109	$ 196	$ 2,305	$ 1,751	$ 182	$ 1,933

(a) Includes Duke Energy's 50 percent interest in DEFS subsequent to deconsolidation of DEFS on July 1, 2005.

(b) Includes Duke Energy's effective 50 percent interest in Crescent subsequent to deconsolidation of Crescent during September 2006

Equity in Earnings of Unconsolidated Affiliates

	For the Years Ended:								
	December 31, 2006			December 31, 2005			December 31, 2004		
	Domestic	International	Total	Domestic	International	Total	Domestic	International	Total
	(in millions)								
U.S. Franchised Electric and Gas	$ (2)	$ —	$ (2)	$ —	$ —	$ —	$ —	$ —	$ —
Natural Gas Transmission	33	2	35	42	5	47	26	4	30
Field Services[a]	574	—	574	308	—	308	60	—	60
Commercial Power	21	—	21	—	—	—	—	—	—
International Energy	—	80	80	—	114	114	—	51	51
Crescent[b]	23	—	23	(1)	—	(1)	3	—	3
Other[c]	(2)	3	1	11	—	11	16	1	17
Total	$ 647	$ 85	$ 732	$ 360	$ 119	$ 479	$ 105	$ 56	$ 161

(a) Includes Duke Energy's 50 percent equity in earnings of DEFS subsequent to deconsolidation on July 1, 2005

(b) Includes approximately $15 million for the year ended December 31, 2006 that represents Duke Energy's effective 50% interest in Crescent earnings subsequent to deconsolidation of Crescent in September 2006

(c) Includes equity investments at the corporate level

Summarized Combined Financial Information of Unconsolidated Affiliates

	As of December 31,	
	2006	2005
	(in millions)	
Balance Sheet[a]		
Current assets	$ 3,656	$ 3,414
Non-current assets	10,848	7,744
Current liabilities	(3,354)	(3,395)
Non-current liabilities	(5,155)	(3,237)
Net assets	$ 5,995	$ 4,526

	For the Years Ended December 31,		
	2006	2005	2004
		(in millions)	
Income Statement[(a)]			
Operating revenues	$ 14,259	$ 8,830	$ 7,326
Operating expenses	12,365	7,683	6,872
Net income	1,657	1,075	415

(a) Amounts include DEFS and Crescent for the respective periods subsequent to deconsolidation

Related Party Transactions. Outstanding notes receivable from unconsolidated affiliates were $226 million as of December 31, 2006 and $50 million as of December 31, 2005 Amounts are included in Notes Receivable on the Consolidated Balance Sheets The balance outstanding as of December 31, 2006 represents International Energy's $16 million note receivable from the Campeche project, a 50% owned joint venture, and Duke Energy Ohio and Duke Energy Indiana's $210 million note receivable from Cinergy Receivables Company LLC (Cinergy Receivables) (see Note 23) The outstanding notes receivable had interest rates approximating current market rates

International Energy loaned money to Campeche to assist in the costs to build International Energy received principal and interest payments of approximately $11 million, $5 million and $7 million from Campeche, a 50% owned DEI affiliate, during 2006, 2005 and 2004, respectively

Duke Energy Ohio and Duke Energy Indiana sell their receivables to Cinergy Receivables During 2006 (subsequent to the closing of the Cinergy merger in April 2006), Duke Energy Ohio and Duke Energy Indiana collectively sold approximately $3 5 billion of receivables to Cinergy Receivables and received approximately $3 5 billion in proceeds from the sales, including the notes receivable (see Note 23).

Natural Gas Transmission has a 50% ownership in two pipeline companies, Gulfstream, an operating pipeline, and Islander East, LLC, a development stage pipeline as well as a 50% ownership in a power plant, McMahon Cogeneration Plant, a cogeneration natural gas fired facility transferred to Natural Gas Transmission from DENA during 2005 Natural Gas Transmission provides certain administrative and other services to the pipeline companies and the power plant Natural Gas Transmission recorded recoveries of costs from these affiliates of $19 million, $12 million, and $8 million during 2006, 2005, and 2004, respectively. The outstanding receivable from these affiliates was $5 million and $2 million as of December 31, 2006 and 2005, respectively.

In October 2005, Gulfstream issued $500 million aggregate principal amount of 5 56% Senior Notes due 2015 and $350 million aggregate principal amount of 6 19% Senior Notes due 2025 The proceeds were used by Gulfstream to pay off a construction loan and the balance of the proceeds, net of transaction costs, of approximately $620 million was distributed to the partners based upon their ownership percentage (approximately $310 million was received by Natural Gas Transmission and are included in Distributions from Equity Investments within Cash Flows from Investing Activities in the accompanying Consolidated Statements of Cash Flows).

In December 2005, Duke Energy completed a 140 million Canadian dollars initial public offering on its Canadian income trust fund (the Income Fund) and sold 14 million Trust Units at an offering price of 10 Canadian dollars per Trust Unit In January 2006, a subsequent greenshoe sale of 1 4 million additional Trust Units, pursuant to an overallotment option, were sold at a price of 10 Canadian dollars per Trust Unit. Subsequent to the January 2006 sale of additional Trust Units, Duke Energy held an approximate 58% ownership interest in the businesses of the Income Fund Proceeds of approximately 14 million Canadian dollars are included in Proceeds from Duke Energy Income Fund within Cash Flows from Financing Activities in the Consolidated Statements of Cash Flows In September 2006, the Income Fund sold approximately 9 million previously unissued Trust Units at a price of 12 15 Canadian dollars per Trust Unit for total proceeds of 104 million Canadian dollars, net of commissions and expenses of other expenses of issuance, which is included in Proceeds from Duke Energy Income Fund within Cash Flows from Financing Activities in the Consolidated Statements of Cash Flows The sale of approximately 9 million Trust Units reduced Duke Energy's ownership interest in the businesses of the Income Fund to approximately 46% at December 31, 2006 As a result of the sale of additional Trust Units, Duke Energy recognized an approximate $15 million U S Dollar pre-tax SAB No 51 gain on the sale of subsidiary stock, which is classified in Gain on Sale of Subsidiary Stock on the Consolidated Statements of Operations The proceeds from the offering plus the draw down of approximately 39 million Canadian dollars on an available credit facility were used by the Income Fund to acquire a 100% interest in Westcoast Gas Services, Inc There were no deferred taxes recorded as a result of this transaction

Advance SC LLC, which provides funding for economic development projects, educational initiatives, and other programs, was formed during 2004 U S Franchised Electric and Gas made donations of approximately $24 million and $3 million to the nonconsolidated subsidiary in 2006 and 2005, respectively Additionally, at December 31, 2006, U S Franchised Electric and Gas had a trade payable to Advance SC LLC of approximately $8 million

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

Field Services sells a portion of its residue gas and NGLs to, purchases raw natural gas and other petroleum products from, and provides gathering and transportation services to unconsolidated affiliates (primarily TEPPCO GP, which was sold in February 2005) Total revenues from these affiliates were approximately $98 million for the six months ended June 30, 2005, and $278 million for the year ended December 31, 2004 Total purchases from these affiliates were approximately $77 million for the six months ended June 30, 2005, and $125 million for the year ended December 31, 2004. Total operating expenses were approximately $1 million for the six months ended June 30, 2005, and $4 million for the year ended December 31, 2004 Reductions in revenues and purchases in 2005 as compared to 2004 are principally due to the sale of TEPPCO GP and deconsolidation of DEFS, effective July 1, 2005

In July 2005, DEFS was deconsolidated due to the transfer of a 19 7% interest to ConocoPhillips and has been subsequently accounted for as an equity investment (see Note 2) Duke Energy's 50% of equity in earnings of DEFS for the year ended December 31, 2006 and the period July 1, 2005 through December 31, 2005 was $574 million and $292 million, respectively, and Duke Energy's investment in DEFS as of December 31, 2006 was $1,166 million, which is included in Investments in Unconsolidated Affiliates in the accompanying Consolidated Balance Sheets For the year ended December 31, 2006, Duke Energy had gas sales to, purchases from, and other operating revenues from affiliates of DEFS of approximately $137 million, $41 million and $12 million, respectively As of December 31, 2006, Duke Energy had trade receivables from and trade payables to DEFS amounting to approximately $71 million and $56 million, respectively Between July 1, 2005 and December 31, 2005, Duke Energy had gas sales to, purchases from, and other operating revenues from affiliates of DEFS of approximately $67 million, $65 million and $12 million, respectively. As of December 31, 2005, Duke Energy had trade receivables from and trade payables to DEFS of approximately $18 million and $47 million, respectively Additionally, Duke Energy received approximately $725 million and $360 million for its share of distributions paid by DEFS in 2006 and 2005, respectively Duke Energy has recognized an approximate $64 million receivable as of December 31, 2006 due to its share of quarterly tax distributions declared by DEFS in 2006 and paid in 2007, as compared to $90 million in 2005, which was paid in 2006 Of these distributions $573 million and $287 million were included in Other, assets within Cash Flows from Operating Activities for the years ended 2006 and 2005, respectively, and approximately $152 million and $73 million were included in Distributions from Equity Investments within Cash Flows from Investing Activities for the years ended 2006 and 2005, respectively, within the accompanying Consolidated Statements of Cash Flows Summary financial information for DEFS, which has been accounted for under the equity method since July 1, 2005 is as follows:

	Twelve-months Ended December 31, 2006	Six-months Ended December 31, 2005
	(in millions)	
Operating revenues	$ 12,335	$ 7,463
Operating expenses	$ 11,063	$ 6,814
Operating income	$ 1,272	$ 649
Net income	$ 1,139	$ 584
	December 31, 2006	**December 31, 2005**
	(in millions)	
Current assets	$ 2,129	$ 2,706
Non-current assets	$ 4,767	$ 5,005
Current liabilities	$ 2,177	$ 3,068
Non-current liabilities	$ 2,391	$ 2,038
Minority interest	$ 71	$ 95

As of December 31, 2006, there was an immaterial basis difference between Duke Energy's carrying value of the investment in DEFS and the value of Duke Energy's proportionate share of the underlying net assets in DEFS

DEFS is a limited liability company which is a pass-through entity for U S income tax purposes DEFS also owns corporations who file their own respective, federal, foreign and state income tax returns and income tax expense related to these corporations is included in the income tax expense of DEFS Therefore, DEFS' net income does not include income taxes for earnings which are pass-through to the members based upon their ownership percentage and Duke Energy recognizes the tax impacts of its share of DEFS' pass-through earnings in its income tax expense from continuing operations in the accompanying Consolidated Statements of Operations

In 2005, DEFS formed DCP Midstream Partners, LP (a master limited partnership) DCP Midstream Partners, LP (DCPLP) completed an initial public offering (IPO) transaction in December 2005 that resulted in net proceeds of approximately $210 million As a result, DEFS has a 42 percent ownership interest in DCPLP, consisting of a 40 percent limited partner ownership interest and a 2 percent gen -

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

eral partner ownership interest. DEFS' ownership interest in the general partner of DCP LP is 100 percent. The gain on the IPO transaction has been deferred by DEFS until DEFS converts its subordinated units in DCP to common units, which will occur no earlier than December 31, 2008.

An indirect wholly owned subsidiary of Duke Energy contributed all the membership interest in Crescent to a newly-formed joint venture causing Duke Energy to deconsolidate Crescent as of September 7, 2006 (see Note 2). Duke Energy's 50% of equity in earnings of Crescent for the period from September 8, 2006 through December 31, 2006 was $15 million and Duke Energy's investment in Crescent as of December 31, 2006 was $180 million, which is included in Investments in Unconsolidated Affiliates in the accompanying Consolidated Balance Sheets. Summary financial information for Crescent, which has been accounted for under the equity method since September 7, 2006 is as follows:

	September 7 through December 31, 2006
	(in millions)
Operating revenues	$ 179
Operating expenses	$ 152
Operating income	$ 27
Net income	$ 30

	December 31, 2006
	(in millions)
Current assets	$ 151
Non-current assets	$ 1,810
Current liabilities	$ 211
Non-current liabilities	$ 1,414
Minority interest	$ 31

In the normal course of business, Duke Energy's consolidated subsidiaries enter into energy trading contracts or other derivatives with one another. On a separate company basis, each subsidiary accounts for such contracts as if they were transacted with a third party and records the contracts using the MTM Model or the Accrual Model of Accounting, as applicable. In the consolidation process, the effects of these intercompany contracts are eliminated, and not reflected in Duke Energy's Consolidated Financial Statements.

Also see Note 2, Note 12, Note 15, Note 18 and Note 23 for additional related party information.

12. Impairments, Severance, and Other Charges

International Energy. In 2006, International Energy recorded a $50 million other-than-temporary impairment charge related to an investment in Campeche, a natural gas compression facility in the Cantarell oil field in the Gulf of Mexico. Campeche project revenues are generated from the GCSA with the PEMEX. The current GCSA expired in November 2006 and a nine month extension was executed in October 2006. In the second quarter of 2006, based on ongoing discussions with PEMEX, it was determined that there was a limited future need for Campeche's gas compression services. Management of International Energy determined that it is probable that the Campeche investment will ultimately be sold or the GCSA will be renewed for a significantly lower rate. An other-than-temporary impairment loss was recorded to reduce the carrying value to management's best estimate of realizable value. The charges consist of a $17 million impairment of the carrying value of the equity method investment, which has been classified within (Losses) Gains on Sales and Impairments of Equity Investments in the Consolidated Statements of Operations for the year ended December 31, 2006, and a $33 million reserve against notes receivable from Campeche, which has been classified within Operations, Maintenance and Other in the Consolidated Statements of Operations for the year ended December 31, 2006. The facility ownership will transfer to PEMEX in August 2007. The carrying value of the note at December 31, 2006 was $16 million, which is management's best estimate of the net realizable value of the note receivable from Campeche.

In December 2006, Duke Energy engaged in discussions with a potential buyer of International Energy's assets in Bolivia. Such discussions to sell the assets were subject to a binding agreement between the parties, which was finalized in February 2007, and resulted in the sale of International Energy's 50 percent ownership interest in two hydroelectric power plants near Cochabamba, Bolivia to Eco -

nergy International for approximately $20 million Based upon the agreed upon selling price of the assets, in December 2006 Duke Energy recorded pre-tax impairment charges of approximately $28 million, which was recorded as a component of Impairment and Other Charges on the Consolidated Statements of Operations The impairment charges reduced the carrying value of the assets to the estimated selling price pursuant to the aforementioned agreement As a result of the sale, International Energy no longer has any assets in Bolivia.

A $20 million other than temporary impairment in value of the Campeche investment was recognized during the third quarter of 2005 to write down the investment to its estimated fair value This impairment is classified as a component of (Losses) Gains on Sales and Impairments of Equity Investments in the accompanying Consolidated Statements of Operations

Field Services. During the year ended December 31, 2005, the Field Services business unit recorded a charge of approximately $120 million due to the reclassification into earnings of pre-tax unrealized losses from AOCI as a result of the discontinuance of certain cash flow hedges entered into hedge Field Services' commodity price risk See Note 8 for a discussion of the impacts of the DEFS disposition transaction on certain cash flow hedges

In the third quarter of 2004, Field Services recorded impairments of approximately $22 million related to DEFS operating assets

Additionally, in the third quarter of 2004, Field Services recorded an impairment of approximately $23 million related to equity method investments at DEFS. The impairment is included in (Losses) Gains on Sales and Impairments of Equity Investments on the Consolidated Statements of Operations The impairment charge was related to management's assessment of the recoverability of some equity method investments. Field Services determined that these assets, which are located in the Gulf Coast, were impaired; therefore they were written down to fair value Fair value was determined based on management's best estimates of sales value and/or discounted future cash flow models

Crescent. In the third quarter of 2005, Crescent recognized pre-tax impairment charges of approximately $16 million related to a residential community near Hilton Head Island, South Carolina, that includes both residential lots and a golf club, to reduce the carrying value of the community to its estimated fair value This impairment was recognized as a component of Impairments and Other Charges in the accompanying Consolidated Statements of Operations This community has incurred higher than expected costs and has been impacted by lower than anticipated sales volume The fair value of the remaining community assets was determined based upon management's estimate of discounted future cash flows generated from the development and sale of the community

In the fourth quarter of 2004, Crescent recorded impairment charges of approximately $42 million related to two residential developments in Payson, Arizona, the Rim and Chaparral Pines, and one residential development in Austin, Texas. Twin Creeks The impairment charges were related to long lived assets at the three properties The developments have suffered from slower than anticipated absorption of available inventory Fair value of the assets was determined based on management's assessment of current operating results and discounted future cash flow models. Crescent also recorded bad debt charges of $8 million related to notes receivable due from Rim Golf Investor, LLC and Chaparral Pines Investor, LLC This amount is recorded in Operation, Maintenance and Other on the Consolidated Statements of Operations

Other. See Note 8 for a discussion of the impacts of the DENA exit plan on certain cash flow hedges.

Severance. During the period from the effective date of the Cinergy merger through December 31, 2006, Duke Energy accrued approximately $89 million related to voluntary and involuntary severance as a result of the merger with Cinergy (see Note 2). Additionally, Duke Energy recorded approximately $45 million in severance liabilities related to legacy Cinergy that has been included in goodwill

As discussed in Note 13, in June 2006, Duke Energy announced it had reached an agreement to sell CMT, as well as associated contracts managed by these companies, to Fortis, a Benelux-based financial services group As such, results of operations for CMT have been reflected in (Loss) Income from Discontinued Operations, net of tax, from the date of the Cinergy acquisition to the date of sale The sale of CMT was consummated in October 2006 and Duke Energy did not record any material severance liabilities as a result of the disposal

During the fourth quarter of 2006, in connection with Duke Energy's spin-off of Spectra Energy, Duke Energy recognized approximately $12 million of severance costs under its ongoing severance plan Future severance costs under this plan, if any, are not currently estimable

As discussed further in Note 13, during the third quarter of 2005, the Board of Directors of Duke Energy authorized and directed management to execute the sale or disposition of substantially all of DENA's remaining assets and contracts outside the Midwestern United States and certain contractual positions related to the Midwestern assets As a result of this exit plan, during the year ended

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

December 31, 2005, DENA recorded a severance accrual of approximately $22 million, under its ongoing severance plan, related to the anticipated involuntary termination of DENA employees Approximately $2 million of the related pre-tax expense is reflected in Operation, Maintenance and Other and approximately $20 million is reflected in (Loss) Income from Discontinued Operations, net of tax in the accompanying Consolidated Statements of Operations for the year ended December 31, 2005 Additionally, DENA offered certain enhanced severance benefits to employees involuntarily terminated in connection with the DENA disposition plan, which are being recognized over the remaining service period Approximately $3 million of enhanced severance benefits were accrued during the fourth quarter of 2005 During 2006, Duke Energy reversed approximately $9 million of previously recorded severance amounts due to a change in estimate As a result of this exit plan, Duke Energy terminated approximately 207 employees through the end of 2006 Management anticipates future severance costs related to this exit plan, which relate to retention costs associated with future services, not included in the following table will not be material

During 2002, Duke Energy communicated a voluntary and involuntary severance program across all segments to align the business with market conditions during that period Severance plans related to the program were amended effective August 1, 2004 and applied to individuals notified of layoffs between that date and January 1, 2006

Severance Reserve	Balance at January 1, 2006	Provision/ Adjustments	Noncash Adjustments	Cash Reductions	Balance at December 31, 2006
			(in millions)		
Natural Gas Transmission	$ 3	$ —	$ —	$ (1)	$ 2
Other(c)	28	146	(11)	(103)	60
Total(a)	$ 31	$ 146	$ (11)	$ (104)	$ 62
	Balance at January 1, 2005	**Provision/ Adjustments**	**Noncash Adjustments**	**Cash Reductions**	**Balance at December 31, 2005**
U.S. Franchised Electric and Gas	$ 4	$ —	$ (2)	$ (2)	$ —
Natural Gas Transmission	6	1	(1)	(3)	3
Field Services(b)	—	1	(1)	—	—
International Energy	1	—	(1)	—	—
Other(c)	4	26	—	(2)	28
Total(a)	$ 15	$ 28	$ (5)	$ (7)	$ 31
	Balance at January 1, 2004	**Provision/ Adjustments**	**Noncash Adjustments**	**Cash Reductions**	**Balance at December 31, 2004**
U.S. Franchised Electric and Gas	$ 60	$ —	$ (6)	$ (50)	$ 4
Natural Gas Transmission	29	1	(6)	(18)	6
Field Services(b)	6	1	—	(7)	—
International Energy	6	—	(4)	(1)	1
Other(c)	49	3	(5)	(43)	4
Total(a)	$ 150	$ 5	$ (21)	$ (119)	$ 15

(a) Substantially all expected severance costs will be applied to the reserves within one year

(b) Includes minority interest

(c) Severance expense included in (Loss) Income From Discontinued Operations, net of tax in the Consolidated Statements of Operations was $(9) million, $22 million, and $1 million for 2006, 2005, and 2004, respectively

Notes To Consolidated Financial Statements—(Continued)

13. Discontinued Operations and Assets Held for Sale

The following table summarizes the results classified as (Loss) Income from Discontinued Operations, net of tax, in the accompanying Consolidated Statements of Operations

Discontinued Operations (in millions)

	Operating Income (Loss)				Net Gain (Loss) on Dispositions			
	Operating Revenues	Pre-tax Operating Income (Loss)	Income Tax Expense (Benefit)	Operating Income (Loss), Net of Tax	Pre-tax Gain (Loss) on Dispositions	Income Tax Expense (Benefit)	Gain (Loss) on Dispositions, Net of Tax	(Loss) Income from Discontinued Operations, Net of Tax
Year Ended December 31, 2006								
Commercial Power	$ 34	$ (7)	$ (7)	$ —	$ 33	$ 50	$ (17)	$ (17)
International Energy	—	(3)	2	(5)	(10)	(3)	(7)	(12)
Other[(a)]	749	(56)	(10)	(46)	(127)	(46)	(81)	(127)
Total consolidated	$ 783	$ (66)	$ (15)	$ (51)	$ (104)	$ 1	$ (105)	$ (156)
Year Ended December 31, 2005								
Field Services	$ 4	$ —	$ —	$ —	$ —	$ —	$ —	$ —
International Energy	—	(3)	1	(4)	—	—	—	(4)
Crescent	2	1	—	1	10	4	6	7
Other[(a)]	2,670	(658)	(243)	(415)	(481)	(192)	(289)	(704)
Total consolidated	$ 2,676	$ (660)	$ (242)	$ (418)	$ (471)	$ (188)	$ (283)	$ (701)
Year Ended December 31, 2004								
Field Services	$ 79	$ 3	$ 1	$ 2	$ (17)	$ (6)	$ (11)	$ (9)
International Energy	85	(13)	(1)	(12)	295	22	273	261
Crescent	2	—	—	—	9	4	5	5
Other[(a)]	3,125	20	34	(14)	1	—	1	(13)
Total consolidated	$ 3,291	$ 10	$ 34	$ (24)	$ 288	$ 20	$ 268	$ 244

(a) Other includes the results for DENA's discontinued operations, which were previously reported in the DENA segment

The following table presents the carrying values of the major classes of assets and associated liabilities held for sale in the accompanying Consolidated Balance Sheets as of December 31, 2006 and 2005. Assets held for sale as of December 31, 2006 primarily relate to Duke Energy Indiana's Wabash River Power Station (see Note 2). Assets held for sale as of December 31, 2005 primarily relate to DENA's assets that were sold to LS Power, as discussed further below

Summarized Balance Sheet Information for Assets and Associated Liabilities Held for Sale

	December 31, 2006	December 31, 2005
	(in millions)	
Current assets	$ 28	$ 1,528
Investments and other assets	19	2,059
Property, plant and equipment, net	115	1,538
Total assets held for sale	$ 162	$ 5,125
Current liabilities	$ 26	$ 1,488
Long-term debt	—	61
Deferred credits and other liabilities	18	2,024
Total liabilities associated with assets held for sale	$ 44	$ 3,573

PART II

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

Commercial Power

In June 2006, Duke Energy announced it had reached an agreement to sell CMT, as well as certain Duke Energy Ohio trading contracts, to Fortis, a Benelux-based financial services group In October 2006, the sale transaction was completed Under the purchase and sale agreement, Fortis purchased CMT at a base price of approximately $210 million In addition, Fortis paid approximately $200 million for the portfolio of contracts and an amount equal to the estimated net working capital associated with these companies at the time of close In October 2006, Duke Energy received total pre-tax cash proceeds of approximately $700 million and recorded an approximate $25 million pre-tax gain on the sale Income tax expense recorded as a result of this transaction relates to the approximate $135 million of goodwill included in assets held for sale that was not deductible for tax purposes, thus creating a taxable gain that was greater than the gain for book purposes Results of operations for CMT, as well as certain Duke Energy Ohio trading contracts, have been reflected in (Loss) Income from Discontinued Operations, net of tax, from the date of the Cinergy acquisition through the date of sale

In October 2006, in connection with this transaction, Duke Energy entered into a series of Total Return Swaps (TRS) with Fortis, which are accounted for as mark to market derivatives The TRS offsets the net fair value of the contracts being sold to Fortis The TRS will be cancelled for each underlying contracts as each is transferred to Fortis All economic and credit risk associated with the contracts has been transferred to Fortis as of the date of the sale through the TRS As of December 31, 2006, approximately 70% of the contracts had been novated by Fortis At December 31, 2006, contracts with a net fair value of approximately $43 million remain in Assets Held for Sale and represent contracts that have yet to be novated by Fortis.

Field Services

In December 2004, based upon management's assessment of the probable disposition of some plant and transportation assets in Wyoming, Field Services wrote down the book value of those assets by $4 million ($3 million net of minority interest) to $10 million, which represented the estimated fair value less cost to sell The after tax loss and results of operations related to these assets were included in (Loss) Income from Discontinued Operations, net of tax, in the accompanying Consolidated Statements of Operations In February 2005, these assets were exchanged for certain gathering assets in Oklahoma of equivalent fair value

In December 2004, Field Services sold gas system and treating plant assets in Southeast New Mexico and South Texas, respectively Field Services sold these assets for proceeds of approximately $6 million, with the carrying value being approximately equal to the sales price The after tax loss and related results of operations were included in (Loss) Income from Discontinued Operations, net of tax, in the accompanying Consolidated Statements of Operations

In September 2004, Field Services recorded a pre-tax impairment charge of approximately $23 million ($16 million net of minority interest) related to management's current assessment of some additional gathering, processing, compression and transportation assets in Wyoming being held for sale The estimated fair value of these assets less cost to sell was $27 million The after tax loss and results of operations were included in (Loss) Income from Discontinued Operations, net of tax, in the accompanying Consolidated Statements of Operations In the first quarter of 2005, Field Services sold these assets for proceeds of $28 million, with the carrying value being approximately equal to the sales price

In February 2004, Field Services sold gas gathering and processing plant assets in West Texas to a third party purchaser for a sales price of approximately $62 million, which approximated these assets' carrying value The after tax gain and results of operations related to these assets were included in (Loss) Income from Discontinued Operations, net of tax, in the accompanying Consolidated Statements of Operations

International Energy

In order to eliminate exposure to international markets outside of Latin America and Canada, International Energy decided in 2003 to pursue a possible sale or IPO of International Energy's Asia-Pacific power generation and natural gas transmission business (the Asia-Pacific Business) As a result of this decision, International Energy recorded an after tax loss of $233 million during the fourth quarter of 2003, which represented the excess of the carrying value over the estimated fair value of the business, less estimated costs to sell In the first quarter of 2004, International Energy determined it was likely that a bid in excess of the originally determined fair value would be accepted and thus recorded a $238 million after tax gain related to International Energy's Asia-Pacific Business The after tax gain was included in (Loss) Income from Discontinued Operations, net of tax, in the accompanying Consolidated Statements of Operations and restored the loss recorded during the fourth quarter of 2003

PART II

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

In the second quarter of 2004, International Energy completed the sale of the Asia-Pacific Business to Alinta Ltd for a gross sales price of approximately $1 2 billion This resulted in recording an additional $40 million after tax gain in the second quarter of 2004 The after tax gain was included in (Loss) Income from Discontinued Operations, net of tax, in the accompanying Consolidated Statements of Operations International Energy received approximately $390 million of cash proceeds, net of approximately $840 million of debt retired (as a non-cash financing activity) as part of the Asia-Pacific Business

International Energy held a receivable from Norsk Hydro ASA (Norsk) related to the 2003 sale of International Energy's European business In 2004, International Energy recorded a $14 million ($9 million after tax) allowance against the carrying value of the note based on management's assessment of the probability of not collecting the entire note In first quarter 2006, based on management's best estimate of recoverability, International Energy recorded an allowance of approximately $19 million ($12 million after tax) against this receivable, which was recorded in (Loss) Income From Discontinued Operations, net of tax in the Consolidated Statements of Operations During the second quarter of 2006, International Energy and Norsk signed a settlement agreement in which Norsk agreed to pay International Energy approximately $34 million in full settlement of International Energy's receivable In connection with this settlement, International Energy recorded an approximate $9 million write-up ($5 million after tax) of the receivable through a reduction in the valuation allowance, which was recorded in (Loss) Income From Discontinued Operations, net of tax on the Consolidated Statements of Operations In July 2006, International Energy received the settlement proceeds

~~The operating results related to these operations were included in (Loss) Income from Discontinued Operations, net of tax, in the accompanying Consolidated Statements of Operations.~~

Crescent

Crescent routinely develops real estate projects and operates those facilities until they are substantially leased and a sales agreement is finalized In September 2006, Duke Energy deconsolidated its investment in Crescent (see Note 2) and subsequently accounts for its investment in the Crescent JV under the equity method of accounting Prior to the date of deconsolidation, if Crescent did not retain any significant continuing involvement after the sale, Crescent classified the project as "discontinued operations" as required by SFAS No 144

In 2005, Crescent sold three commercial properties resulting in sales proceeds of approximately $44 million The $6 million after tax gain on these sales was included in (Loss) Income from Discontinued Operations, net of tax, in the accompanying Consolidated Statements of Operations

In 2004, Crescent sold one multi-family, two residential and two commercial properties resulting in sales proceeds of approximately $52 million The $5 million after tax gain on these sales was included in (Loss) Income from Discontinued Operations, net of tax, in the accompanying Consolidated Statements of Operations

Other

During the third quarter of 2005, Duke Energy's Board of Directors authorized and directed management to execute the sale or disposition of substantially all of DENA's remaining assets and contracts outside the Midwestern United States and certain contractual positions related to the Midwestern assets The DENA assets to be divested include:

- Approximately 6,100 MW of power generation located primarily in the Western and Eastern United States, including all of the commodity contracts (primarily forward gas and power contracts) related to these facilities,
- All remaining commodity contracts related to DENA's Southeastern generation operations, which were substantially disposed of in 2004, and certain commodity contracts related to DENA's Midwestern power generation facilities, and
- Contracts related to DENA's energy marketing and management activities, which include gas storage and transportation, structured power and other contracts

The results of operations of DENA's Western and Eastern United States generation assets, including related commodity contracts, certain contracts related to DENA's energy marketing and management activities and certain general and administrative costs, are required to be classified as discontinued operations for current and prior periods in the accompanying Consolidated Statements of Operations

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

Management retained DENA's Midwestern generation assets, consisting of approximately 3,600 MW of power generation, and certain contracts related to the Midwestern generating facilities, as the merger with Cinergy provided a sustainable business model for those assets (see Note 2 for further details on the Cinergy merger). Accordingly, these assets do not qualify for discontinued operations classification and remain in continuing operations as a component of the Commercial Power segment. Also transferred to Commercial Power were DENA's Southeastern generation operations, including related commodity contracts, which do not meet the requirements for discontinued operations classification due to Duke Energy's continuing involvement with these operations. In addition, management will continue to wind down the limited remaining operations of DETM, the results of which will be reported in Other's continuing operations until the wind down of the operations is complete.

In connection with this exit plan, Duke Energy recognized pre-tax losses of approximately $1.1 billion in 2005 in (Loss) Income From Discontinued Operations, net of tax, in the Consolidated Statement of Operations. These losses principally related to:

- The discontinuation of the normal purchase/normal sale exception for certain forward power and gas contracts (an approximate $1.9 billion pre-tax charge)
- The reclassification of approximately $1.2 billion of pre-tax deferred net gains in AOCI for cash flow hedges of forecasted gas purchase and power sale transactions that will no longer occur as a result of the exit plan
- Pre-tax impairments of approximately $0.2 billion to reduce the carrying value of the plants that are expected to be sold to their estimated fair value less cost to sell. Fair value of the assets that are expected to be sold was estimated based upon the signed agreement with LS Power, as discussed below
- Pre-tax losses of approximately $0.4 billion as the result of selling certain gas transportation and structured contracts (as discussed further below), and
- Pre-tax deferred gains in AOCI of approximately $0.2 billion related to the discontinued cash flow hedges of forecasted gas purchase and power sale transactions, which were recognized as the forecasted transactions occurred

As of the September 2005 exit announcement date, management anticipated that additional charges would be incurred related to the exit plan, including termination costs for gas transportation, storage, structured power and other contracts of approximately $600 million to $800 million, which included approximately $40 million to $60 million of severance, retention and other transaction costs (see Note 12). Included in these amounts are the effects of DENA's November 2005 agreement to sell substantially all of its commodity contracts related to the Southeastern generation operations, which were substantially disposed of in 2004, certain commodity contracts related to DENA's Midwestern power generation facilities, and contracts related to DENA's energy marketing and management activities. Excluded from the contracts sold to Barclays are commodity contracts associated with the near-term value of DENA's West and Northeastern generation assets and with remaining gas transportation and structured power contracts. Approximately $700 million has been incurred from the announcement date through December 31, 2006, of which approximately $230 million was incurred during the year ended December 31, 2006, and was recognized in (Loss) Income From Discontinued Operations, net of tax, and approximately $470 million was incurred during the year ended December 31, 2005, approximately $400 million of which was recognized in (Loss) Income From Discontinued Operations, net of tax. As of December 31, 2006 the DENA exit activities are substantially complete and no additional charges are anticipated.

Among other things, the agreement provides that all economic benefits and burdens under the contracts were transferred to Barclays. Cash consideration paid to Barclays amounted to approximately $100 million in 2005 and approximately $600 million in January 2006. Additionally, in January 2006 Barclays provided Duke Energy with cash equal to the net cash collateral posted by DENA under the contracts of approximately $540 million. The novation or assignment of physical power contracts was subject to FERC approval, which was received in January 2006.

In January 2006, Duke Energy signed an agreement to sell to LS Power DENA's entire fleet of power generation assets outside the Midwest, representing approximately 6,100 megawatts of power generation located in the Western and Northeast United States. In May 2006, the transaction with LS Power closed and total proceeds from the sale were approximately $1.56 billion, including certain working capital adjustments. Additional proceeds of up to approximately $40 million were subject to LS Power obtaining certain state regulatory approvals. On July 20, 2006 the Public Utilities Commission of the State of California approved a toll arrangement related to the Moss Landing facility previously sold to LS Power. In August 2006, LS Power made an additional payment to Duke Energy of approximately $40 million, which Duke Energy recorded as an additional gain on the sale of assets.

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

In October 2006, Duke Energy recognized an approximate $38 million pre-tax gain on the sale of available-for-sale securities that were included in Assets Held for Sale on the Consolidated Balance Sheets This gain was recorded as a component of (Loss) Income from Discontinued Operations, net of tax in the Consolidated Statements of Operations

See Note 3 for a discussion of the impacts of this exit activity on Duke Energy's segment presentation

In the fourth quarter of 2006, the last remaining contract related to DEM expired, which completed Duke Energy's exit from DEM's operations. Accordingly, results of operations for DEM for all periods presented have been reclassified to a component of (Loss) Income From Discontinued Operations, net of tax, on the Consolidated Statements of Operations

In the first quarter of 2005, Duke Energy's Grays Harbor facility was sold to an affiliate of Invenergy LLC, resulting in a pre-tax gain of approximately $21 million (excludes any potential contingent consideration)

In the third quarter of 2005, Duke Energy completed the sale of Bayside Power L P (Bayside) to affiliates of Irving Oil Limited (Irving), under which Irving would purchase Duke Energy's 75% interest in Bayside The after tax gain on this sale is included in (Loss) Income from Discontinued Operations, net of tax, in the accompanying Consolidated Statements of Operations. Bayside was consolidated with the adoption of FIN 46R on March 31, 2004 Therefore, Bayside's operating results after March 31, 2004 are included in (Loss) Income from Discontinued Operations, net of tax, in the accompanying Consolidated Statements of Operations. Prior operating results are not included in Discontinued Operations, as Bayside was previously accounted for as an equity method investment.

For the year ended December 31, 2004, Duke Energy's discontinued operations also included sales and impairments of merchant power plants located in Washington ("Grays Harbor" plant), Nevada ("Moapa" plant) and New Mexico ("Luna" plant) (collectively, the deferred plants). The deferred plants were a component of DENA's Western United States generation assets that meets the requirements for discontinued operations classification for current and prior periods in the accompanying Consolidated Statements of Operations Details are as follows:

- The partially completed Moapa facility was sold to Nevada Power Company and resulted in $186 million in net proceeds and a pre-tax gain of approximately $140 million recorded in (Loss) Income from Discontinued Operations, net of tax, in the 2004 Consolidated Statement of Operations.
- The partially completed Luna facility was sold to PNM Resources. Tucson Electric Power and Phelps Dodge Corporation This sale resulted in net proceeds of $40 million and a pre-tax gain of $40 million recorded in (Loss) Income from Discontinued Operations, net of tax, in the 2004 Consolidated Statement of Operations.
- In December 2004, Duke Energy agreed to sell the partially completed Grays Harbor facility to an affiliate of Invenergy LLC and terminated its capital lease associated with the dedicated pipeline which would have transported natural gas to the plant This termination resulted in a $20 million pre-tax charge recorded in (Loss) Income from Discontinued Operations, net of tax, in the 2004 Consolidated Statement of Operations As discussed above, in the first quarter of 2005, Grays Harbor was sold

Additionally, during 2004, the Western and Northeast operations had operating losses, which substantially offset the above 2004 gains During 2004, Duke Energy received approximately $58 million from the sale or collection of all of DCP notes receivable An immaterial after tax gain related to this transaction was included in (Loss) Income from Discontinued Operations, net of tax, in the accompanying Consolidated Statements of Operations

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

14. Property, Plant and Equipment

	Estimated Useful Life	December 31, 2006	December 31, 2005
	(Years)	(in millions)	
Land	—	$ 684	$ 571
Plant—Regulated			
Electric generation, distribution and transmission[a]	20 – 125	29,845	18,935
Natural gas transmission and distribution	20 – 82	12,374	10,810
Gathering and processing facilities[a]	20 – 25	2,219	1,570
Other buildings and improvements[a]	16 – 90	613	388
Plant—Unregulated			
Electric generation, distribution and transmission[a]	20 – 125	6,036	3,869
Natural gas transmission and distribution	20 – 82	68	32
Gathering and processing facilities	20 – 25	198	678
Other buildings and improvements[a]	16 – 90	43	27
Nuclear fuel	4	890	890
Equipment[a]	3 – 40	1,098	669
Vehicles	3 – 25	134	125
Construction in process	—	2,257	946
Other[a]	5 – 122	1,871	1,313
Total property, plant and equipment		58,330	40,823
Total accumulated depreciation—regulated[b], [c]		(15,538)	(10,721)
Total accumulated depreciation—unregulated[c]		(1,345)	(902)
Total net property, plant and equipment		$ 41,447	$ 29,200

(a) Includes capitalized leases: $161 million for 2006 and $48 million for 2005.

(b) Includes accumulated amortization of nuclear fuel: $541 million for 2006 and $583 million for 2005.

(c) Includes accumulated amortization of capitalized leases: $28 million for 2006 and $19 million for 2005.

Capitalized interest, which includes the interest expense component of AFUDC, amounted to $56 million for 2006, $23 million for 2005, and $18 million for 2004.

15. Debt and Credit Facilities

Summary of Debt and Related Terms

	Weighted-Average Rate	Year Due	December 31, 2006	December 31, 2005
			(in millions)	
Unsecured debt	6.6%	2007 – 2036	$ 14,504	$ 12,600
Secured debt	6.5%	2007 – 2024	1,453	1,570
First and refunding mortgage bonds	5.2%	2008 – 2032	1,507	1,214
Capital leases	5.4%	2007 – 2025	94	10
Other debt[a]	4.9%	2007 – 2040	1,875	208
Commercial paper[b]	5.4%		751	383
Fair value hedge carrying value adjustment		2008 – 2032	43	58
Unamortized debt discount and premium, net			(54)	(13)
Total debt[c]			20,173	16,030
Current maturities of long-term debt			(1,605)	(1,400)
Short-term notes payable and commercial paper[d]			(450)	(83)
Total long-term debt[e]			$ 18,118	$ 14,547

(a) Includes $1,329 million and $172 million of Duke Energy pollution control bonds as of December 31, 2006 and 2005, respectively. As of December 31, 2006 and 2005, $408 million and $40 million, respectively, was secured by first and refunding mortgage bonds and $344 million and $77 million, respectively, was secured by a letter of credit.

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

(b) Includes $300 million as of both December 31, 2006 and 2005 that was classified as Long-term Debt on the Consolidated Balance Sheets due to the existence of long-term credit facilities which back-stop these commercial paper balances along with Duke Energy's ability and intent to refinance these balances on a long-term basis The weighted-average days to maturity were 25 days as of December 31, 2006 and 18 days as of December 31, 2005

(c) As of December 31, 2006, $508 million of debt was denominated in Brazilian Reals and $3,820 million of debt was denominated in Canadian dollars As of December 31, 2005, $501 million of debt was denominated in Brazilian Reals and $3,917 million of debt was denominated in Canadian dollars

(d) Weighted-average rates on outstanding short-term notes payable and commercial paper was 5.4% as of December 31, 2006 and 3 3% as of December 31, 2005

(e) The current and non-current portions of Crescent's long-term debt balances of approximately $2 million and approximately $23 million, respectively, as of December 31, 2005, are no longer included in Duke Energy's consolidated debt balance due to the deconsolidation of Crescent in September 2006

Unsecured Debt. At December 31, 2006, approximately $629 million of pollution control bonds and approximately $300 million of commercial paper, which are short-term obligations by nature, were classified as long-term debt on the Consolidated Balance Sheets due to Duke Energy's intent and ability to utilize such borrowings as long-term financing Duke Energy's credit facilities with non-cancelable terms in excess of one year as of the balance sheet date give Duke Energy the ability to refinance these short-term obligations on a long-term basis

~~In November 2006, Union Gas issued 4.85% fixed-rate debenture bonds denominated in 125 million Canadian dollars (approximately $108 million U.S. dollar equivalents as of the~~ closing date) due in 2022

In October 2006, Duke Energy Carolinas issued $150 million in tax-exempt floating rate bonds The bonds are structured as variable rate demand bonds, subject to weekly remarketing and bear a final maturity of 2031 The initial interest rate was set at 3 72% The bonds are supported by an irrevocable 3-year direct-pay letter of credit and were issued through the North Carolina Capital Facilities Finance Agency to fund a portion of the environmental capital expenditures at the Marshall and Belews Creek Steam Stations

In September 2006, prior to the completion of the joint venture transaction of Crescent, as discussed in Note 2, the Crescent JV, Crescent and Crescent's subsidiaries borrowed approximately $1 23 billion principal amount of debt The net proceeds from the debt issuance of approximately $1 21 billion were recorded as a cash inflow within Financing Activities on the Consolidated Statements of Cash Flows and were distributed to Duke Energy As a result of Duke Energy's deconsolidation of Crescent effective September 7, 2006, Crescent's outstanding debt balance of $1,298 million was removed from Duke Energy's Consolidated Balance Sheets

In September 2006, Union Gas Limited (Union Gas) entered into a fixed-rate financing agreement denominated in 165 million Canadian dollars (approximately $148 million in U S dollar equivalents as of the issuance date) due in 2036 with an interest rate of 5 46%

In August 2006, Duke Energy Kentucky issued approximately $77 million principal amount of floating rate tax-exempt notes due August 1, 2027 Proceeds from the issuance were used to refund a like amount of debt on September 1, 2006 then outstanding at Duke Energy Ohio Approximately $27 million of floating rate debt was swapped to a fixed rate concurrent with closing

In June 2006, Duke Energy Indiana issued $325 million principal amount of 6 05% senior unsecured notes due June 15, 2016 Proceeds from the issuance were used to repay $325 million of 6.65% First Mortgage Bonds that matured on June 15, 2006

In November 2005, International Energy issued floating rate debt in Guatemala for $87 million (in USD) and in El Salvador for $75 million (in USD) These debt issuances have variable interest rate terms and mature in 2015

On September 21, 2005, Union Gas entered into a fixed-rate financing agreement denominated in 200 million Canadian dollars (approximately $171 million in U S dollar equivalents as of the issuance date) due in 2016 with an interest rate of 4 64%

In August 2005, DEI issued project-level debt in Peru, of which $75 million is denominated in U S dollars and approximately $34 million (in U S dollar equivalents as of the issuance date) is denominated in Peru Nuevos Soles This debt has terms ranging from four to six years as well as variable or fixed interest rate terms, as applicable

On March 1, 2005, redemption notices were sent to the bondholders of the $100 million PanEnergy 8 625% bonds due in 2025 These bonds were redeemed on April 15, 2005 at a redemption price of 104 03 or approximately $104 million.

Additionally, Duke Capital remarketed $750 million of its 4 32% senior notes due in 2006, underlying Duke Energy's 8 00% Equity Units on August 11, 2004 As a result of the remarketing, the interest rate on the notes was reset to 4 331%, effective August 16, 2004 Duke Capital subsequently exchanged $400 million of the 4.331% notes for $408 million of 5 668% notes due in 2014. This transaction resulted in an approximate $6 million loss, which was included in Interest Expense in the Consolidated Statements of Operations for the year end December 31, 2004 Proceeds from the remarketed notes were used to purchase U S Treasury securities held by the collateral agent and, upon maturity, were used to satisfy the forward stock purchase contract component of the 8% Equity Units in November 2004

DUKE ENERGY CORPORATION
Notes To Consolidated Financial Statements—(Continued)

Convertible Debt. As of December 31, 2006 and 2005, unsecured debt included $110 million and $742 million, respectively, of 1 75% convertible senior notes due in 2023 These senior notes, which were issued in May 2003, are convertible to Duke Energy common stock at a premium of 40% above the May 1, 2003 closing common stock market price of $16 85 per share The senior notes outstanding as of December 31, 2006 are potentially convertible into approximately 4 7 million shares of common stock which are included as outstanding shares in the diluted EPS calculation (see Note 19) The conversion of these senior notes into shares of Duke Energy common stock is contingent upon the occurrence of certain events during specified periods These events include whether the price of Duke Energy common stock reaches specified thresholds, the credit rating of Duke Energy falls below certain thresholds, the convertible notes are called for redemption by Duke Energy, or specified transactions have occurred In addition to the aforementioned events that could trigger early redemption, holders of the senior notes may require Duke Energy to purchase all or a portion of their senior notes for cash on May 15, 2007, May 15, 2012, and May 15, 2017, at a price equal to the principal amount of the senior notes plus accrued interest, if any Duke Energy may redeem for cash all or a portion of the senior notes at any time on or after May 20, 2007, at a price equal to the sum of the issue price plus accrued interest, if any, on the redemption date These convertible senior notes became convertible into shares of Duke Energy common stock during fiscal quarters beginning April 1, 2006 due to the market price of Duke Energy common stock achieving a specified threshold for each respective quarter Holders of the convertible senior notes were allowed to exercise their right to convert on or prior to December 31, 2006 During 2006, approximately 27 million shares of common stock were issued related to this conversion, which resulted in the retirement of approximately $632 million of convertible senior notes During 2005, as a result of the same market price trigger, approximately 1.2 million shares of common stock were issued related to this conversion, which resulted in the retirement of approximately $28 million of convertible senior notes

Secured Debt. *Accounts Receivable Securitization.* Duke Energy securitizes certain accounts receivable through Duke Energy Receivables Finance Company, LLC (DERF), a bankruptcy remote, special purpose subsidiary DERF is a wholly owned limited liability company with a separate legal existence from its parent, and its assets are not intended to be generally available to creditors of Duke Energy As a result of the securitization, Duke Energy sells on a daily basis to DERF, certain accounts receivable arising from the sale of electricity and/or related services as part of Duke Energy's franchised electric business In order to fund its purchases of accounts receivable, DERF has a $300 million secured credit facility, with a commercial paper conduit administered by Citicorp North America, Inc which terminates in September 2008 The credit facility and related securitization documentation contain several covenants, including covenants with respect to the accounts receivable held by DERF as well as a covenant requiring that the ratio of Duke Energy consolidated indebtedness to Duke Energy consolidated capitalization not exceed 65% As of December 31, 2006, the interest rate associated with the credit facility, which is based on commercial paper rates, was 5 8% and $300 million was outstanding under the credit facility The securitization transaction was not structured to meet the criteria for sale treatment under SFAS No 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities," and accordingly is reflected as a secured borrowing in the Consolidated Financial Statements As of December 31, 2006 and 2005, the $300 million outstanding balance of the credit facility was secured by approximately $476 million and $489 million, respectively, of accounts receivable held by DERF The obligations of DERF under the credit facility are non-recourse to Duke Energy

Other Assets Pledged as Collateral. As of December 31, 2006, secured debt also consisted of various project financings, including Maritimes & Northeast Pipeline, LLC, Maritimes & Northeast Pipeline, LP (collectively, M&N Pipeline) A portion of the assets, ownership interest and business contracts in these various projects are pledged as collateral Additionally, as of December 31, 2006, substantially all of U S Franchised Electric and gas's electric plant in service was subject to a mortgage lien securing the first and refunding mortgage bonds.

Floating Rate Debt. Unsecured debt, secured debt and other debt included approximately $3 2 billion of floating-rate debt as of December 31, 2006, and $1 7 billion as of December 31, 2005 As of December 31, 2006 and 2005, $500 million and $488 million of Brazilian debt that is indexed annually to Brazilian inflation was included in floating rate debt Floating-rate debt is primarily based on commercial paper rates or a spread relative to an index such as a London Interbank Offered Rate for debt denominated in U S dollars, and Banker's Acceptances for debt denominated in Canadian dollars As of December 31, 2006 and 2005, the average interest rate associated with floating-rate debt was approximately 4 8% and 6 4%, respectively

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

At December 31, 2006, Other debt included approximately $326 million of notes payable related to Cinergy's Trust Preferred Securities (see Note 23), which will mature in February 2007. The entire outstanding balance of the debt is classified within Current Maturities of Long-term Debt on the Consolidated Balance Sheets at December 31, 2006.

Maturities, Call Options and Acceleration Clauses.

Annual Maturities as of December 31, 2006

	(in millions)
2007	$ 1,605
2008	2,109
2009	1,634
2010	1,435
2011	604
Thereafter	12,336
Total long-term debt[(a)]	$ 19,723

(a) Excludes short-term notes payable and commercial paper of $450 million.

Duke Energy has the ability under certain debt facilities to call and repay the obligation prior to its scheduled maturity. Therefore, the actual timing of future cash repayments could be materially different than the above as a result of Duke Energy's ability to repay these obligations prior to their scheduled maturity.

Duke Energy may be required to repay certain debt should the credit ratings at Duke Energy Carolinas fall to a certain level at Standard & Poor's (S&P) or Moody's Investor Service (Moody's). As of December 31, 2006, Duke Energy had $13 million of senior unsecured notes which mature serially through 2012 that may be required to be repaid if Duke Energy's senior unsecured debt ratings fall below BBB- at S&P or Baa3 at Moody's, and $23 million of senior unsecured notes which mature serially through 2016 that may be required to be repaid if Duke Energy's senior unsecured debt ratings fall below BBB at S&P or Baa2 at Moody's. As of February 1, 2007, Duke Energy Carolinas' senior unsecured credit rating was BBB at S&P and A3 at Moody's.

Available Credit Facilities and Restrictive Debt Covenants. During the year ended December 31, 2006, Duke Energy's consolidated credit capacity increased by approximately $842 million compared to December 31, 2005 primarily due to the merger with Cinergy. This increase was net of other reductions in credit capacity due to the terminations of an $800 million syndicated credit facility and $590 million of other bi-lateral credit facilities. The terminations of these credit facilities primarily reflect Duke Energy's reduced liquidity needs as a result of exiting the former DENA business.

The issuance of commercial paper, letters of credit and other borrowings reduces the amount available under the available credit facilities.

Duke Energy's debt and credit agreements contain various financial and other covenants. Failure to meet those covenants beyond applicable grace periods could result in accelerated due dates and/or termination of the agreements. As of December 31, 2006, Duke Energy was in compliance with those covenants. In addition, some credit agreements may allow for acceleration of payments or termination of the agreements due to nonpayment, or to the acceleration of other significant indebtedness of the borrower or some of its subsidiaries. None of the debt or credit agreements contain material adverse change clauses.

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

Credit Facilities Summary as of December 31, 2006 (in millions)

	Expiration Date	Credit Facilities Capacity	Amounts Outstanding Commercial Paper	Letters of Credit	Total
Duke Energy Corporation					
$400 364-day syndicated[a], [b]					
Total Duke Energy Corporation	December 2007	$ 400	$ —	$ 111	$ 111
Duke Energy Carolinas, LLC					
$600 multi-year syndicated[a], [b], [c]	June 2011		300	4	304
$75 three-year bi-lateral[a], [b]	September 2009				
$75 three-year bi-lateral[a], [b]	September 2009				
Total Duke Energy Carolinas, LLC		750	300	4	304
Spectra Energy Capital LLC					
$600 multi-year syndicated[a], [b]	June 2010		—	13	13
$350 364-day syndicated[b]	November 2007		350	—	350
Total Spectra Energy Capital LLC		950	350	13	363
Westcoast Energy Inc.					
$173 multi-year syndicated[d]	June 2011	173	—	—	—
Union Gas Limited					
$345 364-day syndicated[e]	June 2007	345	—	—	—
Cinergy Corp.					
$1,500 multi-year syndicated[a], [b], [f]	June 2011	1,500	100	11	111
Total[g]		$ 4,118	$ 750	$ 139	$ 889

(a) Credit facility contains an option allowing borrowing up to the full amount of the facility on the day of initial expiration for up to one year

(b) Credit facility contains a covenant requiring the debt-to-total capitalization ratio to not exceed 65%.

(c) Credit facility increased from $500 million to $600 million in November 2006

(d) Credit facility is denominated in Canadian dollars totaling 200 million Canadian dollars and contains a covenant that requires the debt-to-total capitalization ratio to not exceed 75%

(e) Credit facility is denominated in Canadian dollars totaling 400 million Canadian dollars and contains a covenant that requires the debt-to-total capitalization ratio to not exceed 75% and an option at maturity allowing for the conversion of all outstanding loans to a term loan repayable up to one year after maturity date but not exceeding 18 months from the date of draw.

(f) Contains $500 million sub limits each for Duke Energy Ohio and Duke Energy Indiana and a $100 million sub limit for Duke Energy Kentucky Credit facility decreased from $2 0 billion to $1 5 billion in November 2006.

(g) This summary excludes certain demand facilities and committed facilities that are immaterial in size or which generally support very specific requirements

Duke Energy has approximately $1,095 million of credit facilities which expire in 2007, of which approximately $695 million relates to credit facilities of Spectra Energy Capital Of the $400 million of expiring credit facilities remaining with Duke Energy subsequent to the spin-off of the natural gas businesses (see Note 1), it is Duke Energy's intent to resyndicate these expiring facilities and possibly increase the size of the facilities

Other Loans. During 2006 and 2005, Duke Energy had loans outstanding against the cash surrender value of the life insurance policies that it owns on the lives of its executives The amounts outstanding were $594 million as of December 31, 2006 and $552 million as of December 31, 2005 The amounts outstanding were carried as a reduction of the related cash surrender value that is included in Other Assets on the Consolidated Balance Sheets

DUKE ENERGY CORPORATION
Notes To Consolidated Financial Statements—(Continued)

16. Preferred and Preference Stock at Duke Energy

As of December 31, 2006, as a result of the corporate restructuring in connection with the Cinergy merger, there were 44 million authorized shares of preferred stock, par value $0 001 per share, with no such preferred shares outstanding

As of December 31, 2005, there were no shares of preferred and preference stock outstanding at Duke Energy

Preferred Stock without Sinking Fund Requirements. In December 2005, Duke Energy redeemed all Preferred and Preference stock without Sinking Fund Requirements for approximately $137 million and recognized an immaterial loss on the redemption

Preferred and Preference Stock of Duke Energy's Subsidiaries In connection with the Westcoast acquisition in 2002, Duke Energy assumed approximately $411 million of authorized and issued redeemable preferred and preference shares at Westcoast and Union Gas These preferred and preference shares at Westcoast and Union Gas totaled $225 million at both December 31, 2006 and 2005 Since these preferred and preference shares are redeemable at the option of holder, as well as Westcoast and Union Gas, these preferred and preference shares do not meet the definition of a mandatorily redeemable instrument under SFAS No 150, "Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity " As ~~such, these preferred and preference shares are considered contingently redeemable shares and are included in Minority Interests on the Consolidated Balance Sheets.~~

Additionally, in connection with the Cinergy merger in April 2006, Duke Energy assumed approximately $11 million of authorized and issued preferred stock at Duke Energy Indiana. All outstanding shares of Duke Energy Indiana preferred stock were redeemed in May 2006 at par, plus accrued and unpaid dividends

17. Commitments and Contingencies

General Insurance

Duke Energy carries, either directly or through its captive insurance company, Bison, and its affiliates, insurance and reinsurance coverages consistent with companies engaged in similar commercial operations with similar type properties Duke Energy's insurance coverage includes (1) commercial general public liability insurance for liabilities arising to third parties for bodily injury and property damage resulting from Duke Energy's operations; (2) workers' compensation liability coverage to required statutory limits; (3) automobile liability insurance for all owned, non-owned and hired vehicles covering liabilities to third parties for bodily injury and property damage; (4) insurance policies in support of the indemnification provisions of Duke Energy's by-laws and (5) property insurance covering the replacement value of all real and personal property damage, excluding electric transmission and distribution lines, including damages arising from boiler and machinery breakdowns, earthquake, flood damage and extra expense All coverages are subject to certain deductibles, terms and conditions common for companies with similar types of operations

In 2006, Bison was a member of Oil Insurance Limited (OIL) and sEnergy Insurance Limited (sEnergy), which provided property and business interruption reinsurance coverage respectively for Duke Energy's non-nuclear facilities Duke Energy accounts for its memberships under the cost method, as it does not have the ability to exert significant influence over these investments Bison terminated its membership in OIL effective December 31, 2006 and will pay a withdrawal premium during 2007 as a result of this decision. sEnergy ceased insuring events subsequent to May 15, 2006 and is currently winding down its operations and settling its outstanding claims Bison will continue to pay additional premiums to sEnergy as it settles its outstanding claims during its wind-down Duke Energy does not expect the termination of Bison's membership in OIL or the continued wind-down of sEnergy will have a material impact on its consolidated results of operations, cash flows, or financial position in 2007

Duke Energy also maintains excess liability insurance coverage above the established primary limits for commercial general liability and automobile liability insurance Limits, terms, conditions and deductibles are comparable to those carried by other energy companies of similar size

The cost of Duke Energy's general insurance coverages continued to fluctuate over the past year reflecting the changing conditions of the insurance markets

Nuclear Insurance

Duke Energy owns and operates the McGuire and Oconee Nuclear Stations and operates and has a partial ownership interest in the Catawba Nuclear Station The McGuire and Catawba Nuclear Stations have two nuclear reactors each and Oconee has three Nuclear insurance includes liability coverage; property, decontamination and premature decommissioning coverage; and business interruption and/or extra expense coverage The other joint owners of the Catawba Nuclear Station reimburse Duke Energy for certain expenses associated with nuclear insurance premiums The Price-Anderson Act requires Duke Energy to insure against public liability claims resulting from nuclear incidents to the full limit of liability, approximately $10 8 billion

Primary Liability Insurance Duke Energy has purchased the maximum available private primary liability insurance as required by law, which is $300 million

Excess Liability Program. This program currently provides approximately $10 5 billion of coverage through the Price-Anderson Act's mandatory industry-wide excess secondary financial protection program of risk pooling The $10 5 billion is the sum of the current potential cumulative retrospective premium assessments of $101 million per licensed commercial nuclear reactor This would be increased by $101 million for each additional commercial nuclear reactor licensed, or reduced by $101 million for nuclear reactors no longer operational and may be exempted from the risk pooling insurance program Under this program, licensees could be assessed retrospective premiums to compensate for damages in the event of a nuclear incident at any licensed facility in the U S If such an incident should occur and public liability damages exceed primary insurances, licensees may be assessed up to $101 million for each of their licensed reactors, payable at a rate not to exceed $15 million a year per licensed reactor for each incident The $101 million is subject to indexing for inflation and may be subject to state premium taxes

Duke Energy is a member of Nuclear Electric Insurance Limited (NEIL), which provides accidental outage insurance coverage for Duke Energy's nuclear facilities under three policy programs:

Primary Property Insurance. This policy provides $500 million of primary property damage coverage for each of Duke Energy's nuclear facilities

Excess Property Insurance. This policy provides excess property, decontamination and decommissioning liability insurance: $2 25 billion for the Catawba Nuclear Station and $2.0 billion each for the Oconee and McGuire Nuclear Stations

Accidental Outage Insurance This policy provides business interruption and/or extra expense coverage resulting from an accidental outage of a nuclear unit Each McGuire and Catawba unit is insured for up to $3 5 million per week, and the Oconee units are insured for up to $2 8 million per week Coverage amounts decline if more than one unit is involved in an accidental outage Initial coverage begins after a 12-week deductible period for Catawba and a 26-week deductible period for McGuire and Oconee and continues at 100% for 52 weeks and 80% for the next 110 weeks

If NEIL's losses exceed its reserves for any of the above three programs, Duke Energy is liable for assessments of up to 10 times its annual premiums The current potential maximum assessments are: Primary Property Insurance—$38 million, Excess Property Insurance—$46 million and Business Interruption Insurance—$22 million

The other joint owners of the Catawba Nuclear Station are obligated to assume their pro rata share of liability for retrospective premiums and other premium assessments resulting from the Price-Anderson Act's excess secondary financial protection program of risk pooling, or the NEIL policies

Environmental

Duke Energy is subject to international, federal, state and local regulations regarding air and water quality, hazardous and solid waste disposal and other environmental matters These regulations can be changed from time to time, imposing new obligations on Duke Energy

Remediation activities. Like others in the energy industry, Duke Energy and its affiliates are responsible for environmental remediation at various contaminated sites These include some properties that are part of ongoing Duke Energy operations, sites formerly owned or used by Duke Energy entities, and sites owned by third parties Remediation typically involves management of contaminated soils and may involve groundwater remediation Managed in conjunction with relevant federal, state and local agencies, activities vary with site conditions and locations, remedial requirements, complexity and sharing of responsibility If remediation activities involve statutory joint and several liability provisions, strict liability, or cost recovery or contribution actions, Duke Energy or its affiliates could potentially be held responsible for contamination caused by other parties In some instances, Duke Energy may share liability associated with contamination with other potentially responsible parties, and may also benefit from insurance policies or contractual indemnities that cover some or all cleanup costs All of these sites generally are managed in the normal course of business or affiliate

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

operations Management believes that completion or resolution of these matters will have no material adverse effect on Duke Energy's consolidated results of operations, cash flows or financial position

Clean Water Act The U S Environmental Protection Agency's (EPA's) final Clean Water Act Section 316(b) rule became effective July 9, 2004 The rule established aquatic protection requirements for existing facilities that withdraw 50 million gallons or more of water per day from rivers, streams, lakes, reservoirs, estuaries, oceans, or other U S waters for cooling purposes Fourteen of the 23 coal and nuclear-fueled generating facilities in which Duke Energy is either a whole or partial owner are affected sources under that rule On January 25, 2007, the U S Court of Appeals for the Second Circuit issued its opinion in *Riverkeeper, Inc. v. EPA*, Nos 04-6692-ag(L) et al (2d Cir 2007) remanding most aspects of EPA's rule back to the agency The court effectively disallowed those portions of the rule most favorable to industry, and the decision creates a great deal of uncertainty regarding future requirements and their timing While Duke Energy is still unable to estimate costs to comply with the EPA's rule, it is expected that costs will increase as a result of the court's decision The magnitude of any such increase cannot be estimated at this time

Clean Air Mercury Rule (CAMR) and Clean Air Interstate Rule (CAIR). The EPA finalized its CAMR and CAIR in May 2005 The CAMR limits total annual mercury emissions from coal-fired power plants across the United States through a two-phased cap-and-trade program Phase 1 begins in 2010 and Phase 2 begins in 2018 The CAIR limits total annual and summertime nitrogen oxides (NOx) emissions and annual sulfur dioxide (SO_2) emissions from electric generating facilities across the Eastern United States through a two-phased cap-and-trade program. Phase 1 begins in 2009 for NOx and in 2010 for SO_2. Phase 2 begins in 2015 for both NOx and SO_2

The emission controls Duke Energy is installing to comply with North Carolina clean air legislation will contribute significantly to achieving compliance with CAMR and CAIR requirements (see Note 4) In addition, Duke Energy currently estimates that it will spend approximately $710 million between 2007 and 2011 to comply with Phase 1 of CAMR and CAIR at its Midwest electric operations Duke Energy currently estimates that any additional costs it might incur to comply with Phase 1 of CAMR or CAIR will have no material adverse effect on its consolidated results of operations, cash flows or financial position Duke Energy currently estimates its CAIR Phase 2 compliance costs at approximately $150 million for Duke Energy Carolinas' electric operations over the period 2010-2016 Duke Energy estimates its CAIR/CAMR Phase 2 compliance costs at approximately $450 million for its Midwest electric operations over the period 2007-2016 Duke Energy is currently unable to estimate the cost of complying with Phase 2 of CAMR beyond 2016 The IURC issued an order in 2006 granting Duke Energy Indiana approximately $1 08 billion in rate recovery to cover its estimated Phase 1 of CAIR/CAMR compliance costs in Indiana (see Note 4) Duke Energy Ohio receives partial recovery of depreciation and financing costs related to environmental compliance projects for 2005-2008 through its rate stabilization plan (see Note 4)

Extended Environmental Activities, Accruals. Included in Other Current Liabilities and Other Deferred Credits and Other Liabilities on the Consolidated Balance Sheets were total accruals related to extended environmental-related activities of approximately $73 million and $55 million as of December 31, 2006 and 2005, respectively These accruals represent Duke Energy's provisions for costs associated with remediation activities at some of its current and former sites, as well as other relevant environmental contingent liabilities Management believes that completion or resolution of these matters will have no material adverse effect on Duke Energy's consolidated results of operations, cash flows or financial position

Litigation

New Source Review (NSR) In 1999-2000, the U S Justice Department, acting on behalf of the EPA, filed a number of complaints and notices of violation against multiple utilities across the country for alleged violations of the NSR provisions of the Clean Air Act (CAA) Generally, the government alleged that projects performed at various coal-fired units were major modifications, as defined in the CAA, and that the utilities violated the CAA when they undertook those projects without obtaining permits and installing emission controls for SO_2, NOx and particulate matter The complaints seek (1) injunctive relief to require installation of pollution control technology on various allegedly violating generating units, and (2) unspecified civil penalties in amounts of up to $27,500 per day for each violation A number of Duke Energy's owned and operated plants have been subject to these allegations and lawsuits Duke Energy asserts that there were no CAA violations because the applicable regulations do not require permitting in cases where the projects undertaken are "routine" or otherwise do not result in a net increase in emissions

In 2000, the government brought a lawsuit against Duke Energy in the U S District Court in Greensboro, North Carolina The EPA claims that 29 projects performed at 25 of Duke Energy's coal-fired units in the Carolinas violate these NSR provisions In August 2003, the trial Court issued a summary judgment opinion adopting Duke Energy's legal positions, and on April 15, 2004, the Court entered Final

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

Judgment in favor of Duke Energy The government appealed the case to the U S Fourth Circuit Court of Appeals On June 15, 2005, the Fourth Circuit ruled in favor of Duke Energy and effectively adopted Duke Energy's view that permitting of projects is not required unless the work performed causes a net increase in the hourly rate of emissions The Fourth Circuit did not reach the question of "routine". The EPA sought rehearing in the Fourth Circuit, which was denied Environmental intervenors in the case sought a writ of certiorari to the U S Supreme Court, which was granted On November 1, 2006, oral arguments were made before the U S Supreme Court

In November 1999, the United States brought a lawsuit in the United States Federal District Court for the Southern District of Indiana against Cinergy, Duke Energy Ohio, and Duke Energy Indiana alleging various violations of the CAA for various projects at six of Duke Energy owned and co-owned generating stations in the Midwest Additionally, the suit claims that Duke Energy violated an Administrative Consent Order entered into in 1998 between the EPA and Cinergy relating to alleged violations of Ohio's State Implementation Plan (SIP) provisions governing particulate matter at Unit 1 at Duke Energy Ohio's W C Beckjord Station In addition, three northeast states and two environmental groups have intervened in the case In August 2005, the district court issued a ruling regarding the emissions test that it will apply to Cinergy, Duke Energy Ohio, and Duke Energy Indiana at the trial of the case Contrary to Cinergy's, Duke Energy Ohio's, and Duke Energy Indiana's argument (and the decision of the district court in the Duke Carolinas NSR case described above), the district court ruled that in determining whether a project was projected to increase annual emissions, it would not hold hours of operation constant However, the district court subsequently certified the matter for interlocutory appeal to the Seventh Circuit Court of Appeals In August 2006, the Seventh Circuit upheld the district court's opinion Cinergy has petitioned the U S Supreme Court for a writ of certiorari, which is pending This issue is before the U S. Supreme Court in the Duke Energy Carolinas NSR case, and we do not expect further dispositive legal proceedings in this case until after the Supreme Court ruling

In March 2000, the United States also filed in the United States District Court for the Southern District of Ohio an amended complaint in a separate lawsuit alleging violations of the CAA regarding various generating stations, including a generating station operated by Columbus Southern Power Company (CSP) and jointly-owned by CSP, The Dayton Power and Light Company (DP&L), and Duke Energy Ohio This suit is being defended by CSP (the CSP case) In April 2001, the United States District Court for the Southern District of Ohio in that case ruled that the Government and the intervening plaintiff environmental groups cannot seek monetary damages for alleged violations that occurred prior to November 3, 1994; however, they are entitled to seek injunctive relief for such alleged violations Neither party appealed that decision This matter was heard in trial in July 2005 A decision is pending, but any finding of liability will also be dependent upon the Supreme Court's decision in the Duke Energy Carolinas case

In addition, Cinergy and Duke Energy Ohio have been informed by DP&L that in June 2000, the EPA issued a Notice of Violation (NOV) to DP&L for alleged violations of CAA requirements at a station operated by DP&L and jointly-owned by DP&L, CSP, and Duke Energy Ohio The NOV indicated the EPA may (1) issue an order requiring compliance with the requirements of the Ohio SIP, or (2) bring a civil action seeking injunctive relief and civil penalties of up to $27,500 per day for each violation In September 2004, Marilyn Wall and the Sierra Club brought a lawsuit against Duke Energy Ohio, DP&L and CSP for alleged violations of the CAA at this same generating station This case is currently in discovery in front of the same judge who has the CSP case

It is not possible to predict with certainty whether Duke Energy will incur any liability or to estimate the damages, if any, that Duke Energy might incur in connection with these matters

Carbon Dioxide Litigation In July 2004, the states of Connecticut, New York, California, Iowa, New Jersey, Rhode Island, Vermont, Wisconsin, and the City of New York brought a lawsuit in the United States District Court for the Southern District of New York against Cinergy, American Electric Power Company, Inc , American Electric Power Service Corporation, The Southern Company, Tennessee Valley Authority, and Xcel Energy Inc A similar lawsuit was filed in the United States District Court for the Southern District of New York against the same companies by Open Space Institute, Inc . Open Space Conservancy, Inc , and The Audubon Society of New Hampshire These lawsuits allege that the defendants' emissions of carbon dioxide (CO_2) from the combustion of fossil fuels at electric generating facilities contribute to global warming and amount to a public nuisance The complaints also allege that the defendants could generate the same amount of electricity while emitting significantly less CO_2 The plaintiffs are seeking an injunction requiring each defendant to cap its CO_2 emissions and then reduce them by a specified percentage each year for at least a decade In September 2005, the district court granted the defendants' motion to dismiss the lawsuit The plaintiffs have appealed this ruling to the Second Circuit Court of Appeals Oral argument was held before the Second Circuit Court of Appeals on June 7, 2006

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

It is not possible to predict with certainty whether Duke Energy will incur any liability or to estimate the damages, if any, that Duke Energy might incur in connection with this matter

Hurricane Katrina Lawsuit. In April 2006, Duke Energy and Cinergy were named in the third amended complaint of a purported class action lawsuit filed in the United States District Court for the Southern District of Mississippi Plaintiffs claim that Duke Energy and Cinergy, along with numerous other utilities, oil companies, coal companies and chemical companies, are liable for damages relating to losses suffered by victims of Hurricane Katrina Plaintiffs claim that defendants' greenhouse gas emissions contributed to the frequency and intensity of storms such as Hurricane Katrina In October 2006, Duke Energy and Cinergy were served with this lawsuit It is not possible to predict with certainty whether Duke Energy or Cinergy will incur any liability or to estimate the damages, if any, that Duke Energy or Cinergy might incur in connection with this matter

San Diego Price Indexing Cases. Duke Energy and several of its affiliates, as well as other energy companies, are parties to 25 lawsuits which have been coordinated as the "Price Indexing Cases" in San Diego, California Twelve of the lawsuits seek class-action certification The plaintiffs allege that the defendants conspired to manipulate price of natural gas in violation of state and/or federal antitrust laws, unfair business practices and other laws Plaintiffs in some of the cases further allege that such activities, including engaging in "round trip" trades, providing false information to natural gas trade publications and unlawfully exchanging information, resulted in artificially high energy prices In December 2006, Duke Energy executed an agreement to settle the 12 class action cases Such agreement is subject to execution of mutually acceptable agreements and approval by the class members and the court Duke Energy does not expect that the proposed settlement will have a material adverse effect on its consolidated results of operations, cash flows or financial position

Other Price Reporting Cases A total of 11 lawsuits have been filed against Duke Energy affiliates and other energy companies, including a lawsuit filed in December 2006 in Wisconsin state court In February 2007, Duke Energy was served in the Wisconsin case Six of these cases were dismissed on filed rate and/or federal preemption grounds, and the plaintiffs in each of these dismissed cases have appealed their respective rulings to the U S Ninth Circuit Court of Appeals Oral argument on these appeals was heard February 13, 2007 Each of these cases contains similar claims, that the respective plaintiffs, and the classes they claim to represent, were harmed by the defendants' alleged manipulation of the natural gas markets by various means, including providing false information to natural gas trade publications and entering into unlawful arrangements and agreements in violation of the antitrust laws of the respective states Plaintiffs seek damages in unspecified amounts Duke Energy is unable to express an opinion regarding the probable outcome or estimate damages, if any, related to these matters at this time

Western Electricity Litigation Plaintiffs, on behalf of themselves and others, in three lawsuits allege that Duke Energy Affiliates, among other energy companies, artificially inflated the price of electricity in certain western states Two of the cases were dismissed and plaintiffs have appealed to the U S Court of Appeal for the Ninth Circuit In December 2006, a fourth case, the single remaining electricity case pending in California state court was dismissed Plaintiffs in these cases seek damages in unspecified amounts, but which could total billions of dollars It is not possible to predict with certainty whether Duke Energy will incur any liability or to estimate the damages, if any, that Duke Energy might incur in connection with these lawsuits, but Duke Energy does not presently believe the outcome of these matters will have a material adverse effect on its results of operations, cash flows or financial position

Trading Related Investigations. Beginning in February 2004, Duke Energy has received requests for information from the U S Attorney's office in Houston focused on the natural gas price reporting activities of certain individuals involved in DETM trading operations Duke Energy has cooperated with the government in this investigation and is unable to express an opinion regarding the probable outcome or estimate damages, if any, related to this matter at this time

Southern California Edison In 2002, Southern California Edison Company initiated arbitration proceedings regarding disputes with DETM relating to amounts owed in connection with the termination of bi-lateral power contracts between the parties in early 2001 This matter proceeded to hearing in November 2005 In January 2006, the parties reached an agreement in principle to resolve the matters at issue in the arbitration The parties entered into a Settlement Agreement and Mutual Release dated as of March 10, 2006, and on March 24, 2006, DETM paid the settlement amount, including interest, into escrow The agreement received final regulatory approval in October 2006 The resolution of this matter did not have a material adverse effect on Duke Energy's consolidated results of operations, cash flows or financial position

Trading Related Litigation. Commencing August 2003, plaintiffs filed three class-action lawsuits in the U S District Court for the Southern District of New York on behalf of entities who bought and sold natural gas futures and options contracts on the New York Mer -

DUKE ENERGY CORPORATION
Notes To Consolidated Financial Statements—(Continued)

cantile Exchange during the years 2000 through 2002 DETM and CMT, along with numerous other entities, were named as defendants The plaintiffs claim that the defendants violated the Commodity Exchange Act by reporting false and misleading trading information to trade publications, resulting in monetary losses to the plaintiffs Plaintiffs seek class action certification, unspecified damages and other relief On September 24, 2004, the court denied a motion to dismiss the plaintiffs' claims filed on behalf of DETM and other defendants, and on September 30, 2005, the court certified the class Duke Energy has reached an agreement with the plaintiffs in these consolidated cases to resolve all issues and on February 8, 2006, the court granted preliminary approval of this settlement The Final Judgment and Order of Dismissal were entered in May 2006 The resolution of this matter did not have a material adverse effect on Duke Energy's consolidated results of operations, cash flows or financial position

Sonatrach/Sonatrading Arbitration Duke Energy LNG Sales Inc (Duke LNG) claims in an arbitration commenced in January 2001 in London that Sonatrach, the Algerian state-owned energy company, together with its subsidiary, Sonatrading Amsterdam B V (Sonatrading), breached their shipping obligations under a liquefied natural gas (LNG) purchase agreement and related transportation agreements (the LNG Agreements) relating to Duke LNG's purchase of LNG from Algeria and its transportation by LNG tanker to Lake Charles, Louisiana Duke LNG seeks damages of approximately $27 million Sonatrading and Sonatrach, on the other hand, claim that Duke LNG repudiated the LNG Agreements by allegedly failing to diligently perform LNG marketing obligations Sonatrading and Sonatrach seek damages in the amount of approximately $250 million In 2003, an arbitration tribunal issued a Partial Award on liability issues, finding that Sonatrach and Sonatrading breached their obligations to provide shipping. The tribunal also found that Duke LNG breached the LNG Purchase Agreement by failing to perform marketing obligations The final hearing on damages was concluded in March 2006, and the tribunal issued its award on damages on November 30, 2006 Duke LNG was awarded approximately $20 million, plus interest, for Sonatrach's breach of its shipping obligations Sonatrach and Sonatrading were awarded an unspecified amount that management believes will, when calculated, be substantially less than the amount awarded to Duke LNG, and result ultimately in a net positive, but immaterial, award to Duke LNG This matter was assigned to Spectra Energy in connection with the spin-off in January 2007.

Citrus Trading Corporation (Citrus) Litigation In conjunction with the Sonatrach LNG Agreements, Duke LNG entered into a natural gas purchase contract (the Citrus Agreement) with Citrus Citrus filed a lawsuit in March 2003 in the U S District Court for the Southern District of Texas against Duke LNG and PanEnergy Corp alleging that Duke LNG breached the Citrus Agreement by failing to provide sufficient volumes of gas to Citrus. Duke LNG contends that Sonatrach caused Duke LNG to experience a loss of LNG supply that affected Duke LNG's obligations and termination rights under the Citrus Agreement Citrus seeks monetary damages and a judicial determination that Duke LNG did not experience such a loss After Citrus filed its lawsuit, Duke LNG terminated the Citrus Agreement and filed a counterclaim asserting that Citrus had breached the agreement by, among other things, failing to provide sufficient security under a letter of credit for the gas transactions Citrus denies that Duke LNG had the right to terminate the agreement and contends that Duke LNG's termination of the agreement was itself a breach, entitling Citrus to terminate the agreement and recover damages in the amount of approximately $190 million (excluding interest) This matter and the financial obligation of any settlement or judgment were assigned to Spectra Energy in connection with the spin-off in January 2007 In January 2007 Spectra Energy and Citrus settled this litigation for a payment by Spectra Energy to Citrus of $100 million As a result, in 2006, Duke Energy recognized a reserve of $100 million related to the settlement offer

ExxonMobil Disputes. In April 2004, Mobil Natural Gas, Inc (MNGI) and 3946231 Canada, Inc (3946231, and collectively with MNGI, ExxonMobil) filed a Demand for Arbitration against Duke Energy, DETMI Management Inc (DETMI), DTMSI Management Ltd (DTMSI) and other affiliates of Duke Energy MNGI and DETMI are the sole members of DETM DTMSI and 3946231 are the sole beneficial owners of Duke Energy Marketing Limited Partnership (DEMLP, and with DETM, the Ventures) Among other allegations, ExxonMobil alleges that DETMI and DTMSI engaged in wrongful actions relating to affiliate trading, payment of service fees, expense allocations and distribution of earnings in breach of agreements and fiduciary duties relating to the Ventures ExxonMobil seeks to recover actual damages, plus attorneys' fees and exemplary damages; aggregate damages were specified at the arbitration hearing and totaled approximately $125 million (excluding interest) Duke Energy denies these allegations, and has filed counterclaims asserting that ExxonMobil breached its Venture obligations and other contractual obligations By order dated May 2, 2005, the arbitrators granted Duke Energy's Motion for Partial Summary Judgment, effectively eliminating a significant portion of ExxonMobil's claims ExxonMobil filed a motion for reconsideration of the ruling as well as for an extension of the date for the arbitration hearing. ExxonMobil also filed a motion to dismiss certain of Duke Energy's counterclaims Following a hearing in December 2005 on the motion for reconsideration, the arbitrators issued their ruling on January 26, 2006, generally reaffirming the original order, with a limited exception with respect to affiliate trades that is not expected to have a significant impact on the case. The panel also dismissed one of Duke Energy's counterclaims The parties agreed that the dam -

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

ages due to Duke Energy on its counterclaim will be determined in the upcoming hearing scheduled in the Canadian arbitration proceedings The arbitration hearing in the U S arbitration was held in October 2006 in Houston, Texas, with a subsequent hearing in January 2007 In August 2004, DEMLP initiated arbitration proceedings in Canada against certain ExxonMobil entities asserting that those entities wrongfully terminated two gas supply agreements with the DEMLP and wrongfully failed to assume certain related gas supply agreements with other parties A hearing in the Canadian arbitration was held in March 2006 The arbitrators issued their award in June, 2006 finding that (1) the two gas supply agreements were improperly terminated by ExxonMobil; but (2) ExxonMobil was not required to take assignment of the related third party gas supply agreements Hearings to determine the damages to be paid as the result of the first ruling, as well as the damages to be paid to Duke Energy as the result of the termination of the U S gas supply agreement were held on November 9 and 10, 2006, and January 22, 2007, before the same panel of arbitrators In February 2007, Duke Energy and ExxonMobil reached agreement in principle on a global settlement of both arbitrations Such agreement is subject to execution of final settlement documents Duke Energy does not expect that the proposed settlement will have a material effect on its consolidated results of operations, cash flows or financial position The gas supply agreements with other parties, under which DEMLP continues to remain obligated, are currently estimated to result in losses of between $50 million and $100 million through 2011 As Duke Energy has an ownership interest of approximately 60% in DEMLP, only 60% of any losses would impact pretax earnings for Duke Energy However, these losses are subject to change in the future in the event of changes in market conditions and underlying assumptions

Duke Energy Retirement Cash Balance Plan A class action lawsuit has been filed in federal court in South Carolina against Duke Energy and the Duke Energy Retirement Cash Balance Plan, alleging violations of Employee Retirement Income Security Act (ERISA) and the Age Discrimination in Employment Act These allegations arise out of the conversion of the Duke Energy Company Employees' Retirement Plan into the Duke Energy Retirement Cash Balance Plan The case also raises some Plan administration issues, alleging errors in the application of Plan provisions (*e g.*, the calculation of interest rate credits in 1997 and 1998 and the calculation of lump-sum distributions) The plaintiffs seek to represent present and former participants in the Duke Energy Retirement Cash Balance Plan This group is estimated to include approximately 36,000 persons The plaintiffs also seek to divide the putative class into sub-classes based on age Six causes of action are alleged, ranging from age discrimination, to various alleged ERISA violations, to allegations of breach of fiduciary duty The plaintiffs seek a broad array of remedies, including a retroactive reformation of the Duke Energy Retirement Cash Balance Plan and a recalculation of participants'/ beneficiaries' benefits under the revised and reformed plan Duke Energy filed its answer in March 2006 A second class action lawsuit was filed in federal court in South Carolina, alleging similar claims and seeking to represent the same class of defendants The second case has been voluntarily dismissed, without prejudice, effectively consolidating it with the first case A portion of this liability was assigned to Spectra Energy in connection with the spin-off in January 2007 The matter is currently in discovery with a tentative trial date of March 2008 It is not possible to predict with certainty whether Duke Energy will incur any liability or to estimate the damages, if any, that Duke Energy might incur in connection with this matter

Asbestos-related Injuries and Damages Claims Duke Energy has experienced numerous claims relating to damages for personal injuries alleged to have arisen from the exposure to or use of asbestos in connection with construction and maintenance activities conducted by Duke Energy Carolinas on its electric generation plants during the 1960s and 1970s Duke Energy has third-party insurance to cover losses related to these asbestos-related injuries and damages above a certain aggregate deductible The insurance policy, including the policy deductible and reserves, provided for coverage to Duke Energy up to an aggregate of $1 6 billion when purchased in 2000 Probable insurance recoveries related to this policy are classified in the Consolidated Balance Sheets as Other within Investments and Other Assets Amounts recognized as reserves in the Consolidated Balance Sheets, which are not anticipated to exceed the coverage, are classified in Other Deferred Credits and Other Liabilities and Other Current Liabilities and are based upon Duke Energy's best estimate of the probable liability for future asbestos claims These reserves are based upon current estimates and are subject to uncertainty Factors such as the frequency and magnitude of future claims could change the current estimates of the related reserves and claims for recoveries reflected in the accompanying Consolidated Financial Statements However, management of Duke Energy does not currently anticipate that any changes to these estimates will have any material adverse effect on Duke Energy's consolidated results of operations, cash flows or financial position

Duke Energy Indiana and Duke Energy Ohio have been named as defendants or co-defendants in lawsuits related to asbestos at their electric generating stations Currently, there are approximately 130 pending lawsuits (the majority of which are Duke Energy Indiana cases) In these lawsuits, plaintiffs claim to have been exposed to asbestos-containing products in the course of their work as outside contractors The plaintiffs further claim that as the property owner of the generating stations, Duke Energy Indiana and Duke Energy Ohio should be held liable for their injuries and illnesses based on an alleged duty to warn and protect them from any asbestos exposure The impact on Duke Energy's financial position, cash flows, or results of operations of these cases to date has not been material

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

Of these lawsuits, one case filed against Duke Energy Indiana has been tried to verdict The jury returned a verdict against Duke Energy Indiana on a negligence claim and a verdict for Duke Energy Indiana on punitive damages Duke Energy Indiana appealed this decision up to the Indiana Supreme Court In October 2005, the Indiana Supreme Court upheld the jury's verdict Duke Energy Indiana paid the judgment of approximately $630,000 in the fourth quarter of 2005 In addition, Duke Energy Indiana has settled over 150 other claims for amounts, which neither individually nor in the aggregate, are material to Duke Energy Indiana's financial position or results of operations Based on estimates under varying assumptions, concerning uncertainties, such as, among others: (i) the number of contractors potentially exposed to asbestos during construction or maintenance of Duke Energy Indiana generating plants; (ii) the possible incidence of various illnesses among exposed workers, and (iii) the potential settlement costs without federal or other legislation that addresses asbestos tort actions, Duke Energy estimates that the range of reasonably possible exposure in existing and future suits over the next 50 years could range from an immaterial amount to approximately $60 million, exclusive of costs to defend these cases This estimated range of exposure may change as additional settlements occur and claims are made in Indiana and more case law is established

Duke Energy Ohio has been named in fewer than 10 cases and as a result has virtually no settlement history for asbestos cases. Thus, Duke Energy is not able to reasonably estimate the range of potential loss from current or future lawsuits However, potential judgments or settlements of existing or future claims could be material to Duke Energy

Other Litigation and Legal Proceedings. Duke Energy and its subsidiaries are involved in other legal, tax and regulatory proceedings arising in the ordinary course of business, some of which involve substantial amounts. Management believes that the final disposition of these proceedings will not have a material adverse effect on Duke Energy's consolidated results of operations, cash flows or financial position

Duke Energy has exposure to certain legal matters that are described herein As of December 31, 2006, Duke Energy has recorded reserves of approximately $1 3 billion for these proceedings and exposures Duke Energy has insurance coverage for certain of these losses incurred As of December 31, 2006, Duke Energy has recognized approximately $1 0 billion of probable insurance recoveries related to these losses These reserves represent management's best estimate of probable loss as defined by SFAS No. 5, "Accounting for Contingencies "

Duke Energy expenses legal costs related to the defense of loss contingencies as incurred

Other Commitments and Contingencies

Commercial Power produces synthetic fuel from facilities that qualify for tax credits (through 2007) in accordance with Section 29/45K of the Internal Revenue Code if certain requirements are satisfied These credits reduce Duke Energy's income tax liability and therefore Duke Energy's effective tax rate Commercial Power's sale of synthetic fuel has generated $339 million in tax credits through December 31, 2005 During the first quarter of 2006, an agreement was in place with the plant operator which would indemnify Duke Energy in the event that tax credits are insufficient to support operating expenses This agreement did not continue for the remainder of 2006 After reducing for the possibility of phase-outs in 2006, the amount of additional credits generated through December 31, 2006 was approximately $20 million Duke Energy's net investment in the plants at December 31, 2006 was approximately $20 million.

Section 29/45K provides for a phase-out of the credit if the average price of crude oil during a calendar year exceeds a specified threshold The phase-out is based on a prescribed calculation and definition of crude oil prices. If Commercial Power were to operate its synthetic fuel facilities based on December 31, 2006 prices throughout the entire forthcoming year, yet crude oil prices were to rise such that the tax credit is completely phased-out, net income in 2007 would be negatively impacted Duke Energy is unlikely to experience a material loss because the exposure to synthetic fuel tax credit phase-out is monitored and Duke Energy may choose to reduce or cease synthetic fuel production depending on the expectation of any potential tax credit phase-out. Duke Energy may also reduce its exposure to crude prices through the execution of derivative transactions The objective of these activities is to reduce potential losses incurred if the reference price in a year exceeds a level triggering a phase-out of synthetic fuel tax credits

In August 2006, Duke Energy successfully completed the sale of one of its synthetic fuel facilities resulting in an immaterial gain. This sale was driven by Internal Revenue Service (IRS) requirements that stipulate that in order to qualify for tax credits in accordance with Section 29/45K, the sales of the synthetic fuel must be made to an unrelated third party

The IRS has completed the audit of Cinergy for the 2002, 2003, and 2004 tax years including the synthetic fuel facility owned during that period That facility represents $219 million of tax credits generated during that audit period The IRS has not proposed any adjustment that would disallow the credits claimed during that period Subsequent periods are still subject to audit. Duke Energy believes that it operates in conformity with all the necessary requirements to be allowed such credits under Section 29/45K

Duke Energy is party to an agreement with a third party service provider related to future purchases to be made through late 2007 The agreement contains certain damage payment provisions if the purchases are not made by the specified date The maximum pretax exposure under the agreement is currently estimated at approximately $100 million. In the fourth quarter of 2006, Duke Energy initiated early settlement discussions regarding this agreement and recorded a reserve of approximately $65 million during December of 2006 based upon probable penalty payments to be incurred Future adjustments to this reserve could be material depending on the level of actual purchase commitments

In October 2006, Duke Energy began an internal investigation into improper data reporting to the U S Environmental Protection Agency (USEPA) regarding air emissions under the NOx Budget Program at Duke Energy's DEGS of Narrows, L L C power plant facility in Narrows, Virginia The investigation has revealed evidence of falsification of data by an employee relating to the quality assurance testing of its continuous emissions monitoring system (CEMS) to monitor heat input and NOx emissions In December 2006, Duke Energy voluntarily disclosed the potential violations to the USEPA and Virginia Department of Environmental Quality (VDEQ), and in January 2007, Duke Energy made a full written disclosure of the investigation's findings to the USEPA and the VDEQ. Duke Energy has taken appropriate disciplinary action, including termination, with respect to the employees involved with the false reporting. It is not possible to predict with certainty whether Duke Energy will incur any liability or to estimate the damages, if any, that Duke Energy might incur in connection with this matter

Other As part of its normal business, Duke Energy is a party to various financial guarantees, performance guarantees and other contractual commitments to extend guarantees of credit and other assistance to various subsidiaries, investees and other third parties These arrangements are largely entered into by Duke Energy and Spectra Energy Capital To varying degrees, these guarantees involve elements of performance and credit risk, which are not included on the Consolidated Balance Sheets The possibility of Duke Energy or Spectra Energy Capital having to honor its contingencies is largely dependent upon future operations of various subsidiaries, investees and other third parties, or the occurrence of certain future events (For further information see Note 18)

In addition, Duke Energy enters into various fixed-price, non-cancelable commitments to purchase or sell power (tolling arrangements or power purchase contracts), take-or-pay arrangements, transportation or throughput agreements and other contracts that may or may not be recognized on the Consolidated Balance Sheets Some of these arrangements may be recognized at market value on the Consolidated Balance Sheets as trading contracts or qualifying hedge positions included in Unrealized Gains or Losses on Mark-to-Market and Hedging Transactions (See Note 18 for discussion of Calpine guarantee obligation)

Operating and Capital Lease Commitments

Duke Energy leases assets in several areas of its operations Consolidated rental expense for operating leases was $146 million in 2006, $119 million in 2005 and $124 million in 2004, which is included in Operation, Maintenance and Other on the Consolidated Statements of Operations Amortization of assets recorded under capital leases was included in Depreciation and Amortization on the Consolidated Statements of Operations The following is a summary of future minimum lease payments under operating leases, which at inception had a noncancelable term of more than one year, and capital leases as of December 31, 2006:

	Operating Leases	Capital Leases
	(in millions)	
2007	$ 116	$ 11
2008	108	15
2009	94	16
2010	84	11
2011	59	9
Thereafter	257	32
Total future minimum lease payments	$ 718	$ 94

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

18. Guarantees and Indemnifications

Duke Energy and its subsidiaries have various financial and performance guarantees and indemnifications which are issued in the normal course of business As discussed below, these contracts include performance guarantees, stand-by letters of credit, debt guarantees, surety bonds and indemnifications Duke Energy and its subsidiaries enter into these arrangements to facilitate a commercial transaction with a third party by enhancing the value of the transaction to the third party

In contemplation of the spin-off of the natural gas businesses on January 2, 2007 (see Note 1), certain guarantees that were previously issued by Spectra Energy Capital were transferred to Duke Energy prior to the consummation of the spin-off Under FIN 45, guarantees that are modified after issuance are required to be remeasured at fair value at the date of modification Accordingly, as a result of these modifications, Duke Energy recorded immaterial liability amounts in 2006 associated with these guarantees Additionally, at December 31, 2006, Duke Energy has certain guarantees of wholly-owned subsidiaries that became guarantees of third party performance upon the spin-off of the natural gas businesses in January 2007 Duke Energy has received back-to-back indemnification from Spectra Energy Capital indemnifying Duke Energy for any amounts paid related to these guarantees

Guarantees that were issued by or assigned to Duke Energy, Cinergy or International Energy on or prior to December 31, 2006 remained with Duke Energy subsequent to the spin-off Guarantees issued by Spectra Energy Capital or Natural Gas Transmission on or prior to December 31, 2006 remained with Spectra Energy Capital subsequent to the spin-off, except for certain guarantees discussed below that are in the process of being assigned to Duke Energy During this assignment period, Duke Energy has indemnified Spectra Energy Capital against any losses incurred under these guarantee obligations

Duke Energy has issued performance guarantees to customers and other third parties that guarantee the payment and performance of other parties, including certain non-wholly owned entities The maximum potential amount of future payments Duke Energy could have been required to make under these performance guarantees as of December 31, 2006 was approximately $27 million Approximately $4 million of the performance guarantees expire in 2009, with the remaining performance guarantees having no contractual expiration

Additionally, Duke Energy has issued guarantees to customers or other third parties related to the payment or performance obligations of certain entities that were previously wholly owned by Duke Energy but which have been sold to third parties, such as DukeSolutions, Inc (DukeSolutions) and Duke Engineering & Services, Inc (DE&S) These guarantees are primarily related to payment of lease obligations, debt obligations, and performance guarantees related to provision of goods and services Duke Energy has received back-to-back indemnification from the buyer of DE&S indemnifying Duke Energy for any amounts paid by Spectra Energy Capital related to the DE&S guarantees Duke Energy also received indemnification from the buyer of DukeSolutions for the first $2 5 million paid by Duke Energy related to the DukeSolutions guarantees Further, Duke Energy granted indemnification to the buyer of DukeSolutions with respect to losses arising under some energy services agreements retained by DukeSolutions after the sale, provided that the buyer agreed to bear 100% of the performance risk and 50% of any other risk up to an aggregate maximum of $2 5 million (less any amounts paid by the buyer under the indemnity discussed above) Additionally, for certain performance guarantees, Duke Energy has recourse to subcontractors involved in providing services to a customer These guarantees have various terms ranging from 2007 to 2019, with others having no specific term The maximum potential amount of future payments under these guarantees as of December 31, 2006 was approximately $81 million

Cinergy has issued performance guarantees to customers and other third parties that guarantee the payment and performance of certain non-wholly-owned consolidated entities Additionally, Cinergy has issued guarantees of debt of certain non-consolidated entities and less than wholly owned consolidated entities The maximum potential amount of future payments Cinergy could have been required to make under these performance guarantees as of December 31, 2006 was approximately $171 million Approximately $92 million of the performance guarantees expire between 2008 and 2017, with the remaining performance guarantees having no contractual expiration

Spectra Energy Capital has issued performance guarantees to customers and other third parties that guarantee the payment and performance of other parties, including certain non-wholly owned entities The maximum potential amount of future payments Spectra Energy Capital could have been required to make under these performance guarantees as of December 31, 2006 was approximately $615 million, of which approximately $220 million is in the process of being assigned to Duke Energy, as discussed above Of this amount, approximately $25 million relates to guarantees of the payment and performance of less than wholly owned consolidated entities Approximately $40 million of the performance guarantees expire between 2007 and 2009, with the remaining performance guarantees expiring after 2009 or having no contractual expiration

DUKE ENERGY CORPORATION
Notes To Consolidated Financial Statements—(Continued)

Additionally, Spectra Energy Capital has issued joint and several guarantees to some of the D/FD project owners, guaranteeing the performance of D/FD under its engineering, procurement and construction contracts and other contractual commitments Substantially all of these guarantees have no contractual expiration and no stated maximum amount of future payments that Spectra Energy Capital could be required to make Additionally, Fluor Enterprises Inc., as 50% owner in D/FD, has issued similar joint and several guarantees to the same D/FD project owners In accordance with the D/FD partnership agreement, each of the partners is responsible for 50% of any payments to be made under those guarantees

Westcoast has issued performance guarantees to third parties guaranteeing the performance of unconsolidated entities, such as equity method investments, and of entities previously sold by Westcoast to third parties Those guarantees require Westcoast to make payment to the guaranteed third party upon the failure of such unconsolidated or sold entity to make payment under some of its contractual obligations, such as debt, purchase contracts and leases The maximum potential amount of future payments Westcoast could have been required to make under those performance guarantees as of December 31, 2006 was approximately $15 million Of those guarantees, approximately $10 million expire in 2007, with the remainder having no contractual expiration.

Natural Gas Transmission and International Energy have issued guarantees of debt and performance guarantees associated with non-consolidated entities and less than wholly owned consolidated entities If such entities were to default on payments or performance, Natural Gas Transmission or International Energy would be required under the guarantees to make payment on the obligation of the less than wholly owned entity As of December 31, 2006, Natural Gas Transmission was the guarantor of approximately $17 million of debt at Westcoast associated with less than wholly owned entities, which expire in 2019 International Energy was the guarantor of approximately $13 million of performance guarantees associated with less than wholly owned entities Substantially all of these guarantees expire between 2007 and 2008

Duke Energy uses bank-issued stand-by letters of credit to secure the performance of non-wholly owned entities to a third party or customer Under these arrangements, Duke Energy has payment obligations to the issuing bank which are triggered by a draw by the third party or customer due to the failure of the non-wholly owned entity to perform according to the terms of its underlying contract The maximum potential amount of future payments Duke Energy could have been required to make under these letters of credit as of December 31, 2006 was approximately $55 million Substantially all of these letters of credit were issued on behalf of less than wholly owned consolidated entities and expire in 2007

In connection with Duke Energy's sale of the Murray merchant generation facility to KGen. in August 2004, Duke Energy guaranteed in favor of a bank the repayment of any draws under a $120 million letter of credit issued by the bank to Georgia Power Company The letter of credit, which expires in 2007, is related to the obligation of a KGen subsidiary under a seven-year power sales agreement, commencing in May 2005 Duke Energy will be required to ensure reissuance of this letter of credit or issue similar credit support until the power sales agreement expires in 2012 Duke Energy will operate the sold Murray facility under an operation and maintenance agreement with the KGen subsidiary As a result, the guarantee has an immaterial fair value Further, KGen has agreed to indemnify Duke Energy for any payments Duke Energy makes with respect to the $120 million letter of credit In February 2007, this guarantee was cancelled and Duke Energy has no future obligations associated with this matter

Spectra Energy Capital has guaranteed certain issuers of surety bonds, obligating itself to make payment upon the failure of a non-wholly owned entity to honor its obligations to a third party As of December 31, 2006, Spectra Energy Capital had guaranteed approximately $210 million of outstanding surety bonds related to obligations of non-wholly owned entities The majority of these bonds expire in various amounts in 2007 and 2008 Approximately $206 million of surety bonds were transferred to Duke Energy upon the consummation of the spin-off in January 2007

In 1999, the Industrial Development Corp of the City of Edinburg, Texas (IDC) issued approximately $100 million in bonds to purchase equipment for lease to Duke Hidalgo (Hidalgo), a subsidiary of Duke Energy Spectra Energy Capital unconditionally and irrevocably guaranteed the lease payments of Hidalgo to IDC through 2028 In 2000, Hidalgo was sold to Calpine Corporation and Spectra Energy Capital remained obligated under the lease guaranty In January 2006, Hidalgo and its subsidiaries filed for bankruptcy protection in connection with the previous bankruptcy filing by its parent, Calpine Corporation in December 2005 Gross, undiscounted exposure under the guarantee obligation as of December 31, 2006 is approximately $200 million, including principal and interest payments Duke Energy does not believe a loss under the guarantee obligation is probable as of December 31, 2006, but continues to evaluate the situation Therefore, no reserves have been recorded for any contingent loss as of December 31, 2006 No demands for payment have been made under the guarantee If losses are incurred under the guarantee, Spectra Energy Capital has certain rights which should allow it to miti -

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

gate such loss Subsequent to the spin-off of the natural gas businesses, this guarantee remained with Spectra Energy Capital However, Duke Energy indemnified Spectra Energy Capital against any future losses that could arise from payments required under this guarantee

Duke Energy has entered into various indemnification agreements related to purchase and sale agreements and other types of contractual agreements with vendors and other third parties These agreements typically cover environmental, tax, litigation and other matters, as well as breaches of representations, warranties and covenants Typically, claims may be made by third parties for various periods of time, depending on the nature of the claim Duke Energy's potential exposure under these indemnification agreements can range from a specified amount, such as the purchase price, to an unlimited dollar amount, depending on the nature of the claim and the particular transaction. Duke Energy is unable to estimate the total potential amount of future payments under these indemnification agreements due to several factors, such as the unlimited exposure under certain guarantees

At December 31, 2006, the amounts recorded for the guarantees and indemnifications mentioned above are immaterial, both individually and in the aggregate

19. Earnings Per Share (EPS)

Basic EPS is computed by dividing earnings available for common stockholders by the weighted-average number of common shares outstanding during the period. Diluted EPS is computed by dividing earnings available for common stockholders, as adjusted, by the diluted weighted-average number of common shares outstanding during the period. Diluted EPS reflects the potential dilution that could occur if securities or other agreements to issue common stock, such as stock options, stock-based performance unit awards, contingently convertible debt and phantom stock awards, were exercised, settled or converted into common stock

The following tables illustrate Duke Energy's basic and diluted EPS calculations and reconcile the weighted-average number of common shares outstanding to the diluted weighted-average number of common shares outstanding for 2006, 2005, and 2004

(in millions, except per share data)	Income	Average Shares	EPS
2006			
Income from continuing operations	$ 2,019		
Less: Dividends and premiums on redemption of preferred and preference stock	—		
Income from continuing operations—basic	2,019	1,170	$ 1.73
Effect of dilutive securities:			
Stock options, phantom, performance and restricted stock		4	
Contingently convertible bond	4	14	
Income from continuing operations—diluted	$ 2,023	1,188	$ 1.70
2005			
Income from continuing operations	$ 2,529		
Less: Dividends and premiums on redemption of preferred and preference stock	(12)		
Income from continuing operations—basic	2,517	934	$ 2.69
Effect of dilutive securities:			
Stock options, phantom, performance and restricted stock		4	
Contingently convertible bond	8	32	
Income from continuing operations—diluted	$ 2,525	970	$ 2.60
2004			
Income from continuing operations	$ 1,246		
Less: Dividends and premiums on redemption of preferred and preference stock	(9)		
Income from continuing operations—basic	1,237	931	$ 1.33
Effect of dilutive securities:			
Stock options, phantom, performance and restricted stock		2	
Contingently convertible bond	8	33	
Income from continuing operations—diluted	$ 1,245	966	$ 1.29

The increase in weighted-average shares outstanding for the year ended December 31, 2006 compared to the same period in 2005 was due primarily to the April 2006 issuance of approximately 313 million shares in conjunction with the merger with Cinergy (see Note 2), the conversion of debt into approximately 27 million shares of Duke Energy common stock during the year ended December 31, 2006 (see Note 21), and the repurchase and retirement of approximately 17 5 million shares of Duke Energy common stock during the year ended December 31, 2006 (see Note 21).

As of December 31, 2006, 2005 and 2004, approximately 14 million, 19 million and 23 million, respectively, of options, unvested stock, performance and phantom stock awards were not included in the "effect of dilutive securities" in the above table because either the option exercise prices were greater than the average market price of the common shares during those periods, or performance measures related to the awards had not yet been met

20. Stock-Based Compensation

Effective January 1, 2006, Duke Energy adopted the provisions of SFAS No 123(R) SFAS No 123(R) establishes accounting for stock-based awards exchanged for employee and certain nonemployee services Accordingly, for employee awards, equity classified stock-based compensation cost is measured at the grant date, based on the fair value of the award, and is recognized as expense over the requisite service period Duke Energy previously applied Accounting Principles Board (APB) Opinion No 25, "Accounting for Stock Issued to Employees," and FIN 44, "Accounting for Certain Transactions Involving Stock Compensation (an Interpretation of APB Opinion 25)" and provided the required pro forma disclosures of SFAS No 123 Since the exercise price for all options granted under those plans was equal to the market value of the underlying common stock on the grant date, no compensation cost was recognized in the accompanying Consolidated Statements of Operations

Duke Energy elected to adopt the modified prospective application method as provided by SFAS No 123(R), and accordingly, financial statement amounts from the prior periods presented in this Form 10-K have not been restated. There were no modifications to outstanding stock options prior to the adoption of SFAS 123(R)

Duke Energy recorded pre-tax stock-based compensation expense for the years ended December 31, 2006, 2005 and 2004 as follows, the components of which are further described below:

	For the Years Ended December 31,		
	2006	2005	2004
		(in millions)	
Stock Options	$ 9	$ —	$ —
Stock Appreciation Rights	2	1	1
Phantom Stock	38	21	12
Performance Awards	30	24	12
Other Stock Awards	3	1	1
Total	$ 82	$ 47	$ 26

The tax benefit associated with the recorded expense for the year ended December 31, 2006, 2005 and 2004 was approximately $31 million, $17 million and $10 million, respectively There were no material differences in income from continuing operations, income tax expense, net income, cash flows, or basic and diluted earnings per share from the adoption of SFAS No 123(R)

The following table shows what earnings available for common stockholders, basic earnings per share and diluted earnings per share would have been if Duke Energy had applied the fair value recognition provisions of SFAS No 123(R) to all stock-based compensation awards during prior periods

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

Pro Forma Stock-Based Compensation

	Year ended December 31, 2005	Year ended December 31, 2004
	(in millions, except per share amounts)	
Earnings available for common stockholders, as reported	$ 1,812	$ 1,481
Add: stock-based compensation expense included in reported earnings available to common stockholders, net of related tax effects	30	16
Deduct: total stock-based compensation expense determined under fair value-based method for all awards, net of related tax effects	(32)	(27)
Pro forma earnings available for common stockholders, net of related tax effects	$ 1,810	$ 1,470
Earnings per share:		
Basic—as reported	$ 1.94	$ 1.59
Basic—pro forma	$ 1.94	$ 1.58
Diluted—as reported	$ 1.88	$ 1.54
Diluted—pro forma	$ 1.87	$ 1.53

Duke Energy's 2006 Long-term Incentive Plan (the 2006 Plan), approved by shareholders in October 2006, reserved 60 million shares of common stock for awards to employees and outside directors Duke Energy's 1998 Long-term Incentive Plan, as amended (the 1998 Plan), reserved 60 million shares of common stock for awards to employees and outside directors The 2006 Plan supersedes the 1998 Plan and no additional grants will be made from the 1998 Plan Under the 2006 Plan and the 1998 Plan, the exercise price of each option granted cannot be less than the market price of Duke Energy's common stock on the date of grant and the maximum option term is 10 years The vesting periods range from immediate to five years Duke Energy has historically issued new shares upon exercising or vesting of share-based awards In 2007, Duke Energy may use a combination of new share issuances and open market repurchases for share-based awards which are exercised or vested Duke Energy has not determined with certainty the amount of such new share issuances or open market repurchases

Upon the acquisition of Westcoast Energy, Inc (Westcoast), Duke Energy converted all stock options outstanding under the 1989 Westcoast Long-term Incentive Share Option Plan to Duke Energy stock options Certain of these options also provide for share appreciation rights under which the holder of a stock option may, in lieu of exercising the option, exercise the share appreciation right The exercise price of these options equals the market price on the date of grant and the maximum option term is 10 years The vesting periods range from immediate to four years

Upon the acquisition of Cinergy, Duke Energy converted all stock options outstanding under the Cinergy 1996 Long-Term Incentive Compensation Plan and Cinergy Corp Stock Option Plan to Duke Energy stock options The exercise price of these options equaled the market price on the date of grant and the maximum option term is 10 years The vesting periods are generally three years The 2006 Plan supersedes both Cinergy Plans and no additional grants will be made from these plans

Stock Option Activity

	Options (in thousands)	Weighted-Average Exercise Price	Weighted-Average Remaining Life (in years)	Aggregate Intrinsic Value (in millions)
Outstanding at December 31, 2005	25,506	$ 29		
Granted[(a)]	9,173	24		
Exercised	(6,369)	23		
Forfeited or expired	(1,595)	34		
Outstanding at December 31, 2006	26,715	29	4.9	$ 173
Exercisable at December 31, 2006	21,923	$ 30	4.3	$ 122
Options Expected to Vest	4,744	$ 22	7.92	$ 51

(a) Includes 7,294,994 converted Cinergy stock options

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

On December 31, 2005 and 2004, Duke Energy had approximately 22 million exercisable options with a $32 weighted-average exercise price. The total intrinsic value of options exercised during the years ended December 31, 2006, 2005 and 2004 was approximately $46 million, $17 million and $7 million, respectively. Cash received from options exercised during the year ended December 31, 2006 was approximately $127 million, with a related tax benefit of approximately $17 million. At December 31, 2006, Duke Energy had approximately $7 million of future compensation cost which is expected to be recognized over a weighted-average period of 1.5 years.

In addition to the conversion of the Cinergy stock options noted above, Duke Energy granted 1,877,646 options (fair value of approximately $10 million based on a Black-Scholes model valuation) during the year ended December 31, 2006. There were no options granted during the years ended December 31, 2005 and 2004. Remaining compensation expense to be recognized for unvested converted Cinergy options was determined using a Black-Scholes model.

Weighted-Average Assumptions for Option Pricing	2006
Risk-free interest rate(1)	4.78%
Expected dividend yield(2)	4.40%
Expected life(3)	6.29 yrs.
Expected volatility(4)	24%

(1) The risk free rate is based upon the U.S. Treasury Constant Maturity rates as of the grant date.

(2) The expected dividend yield is based upon annualized dividends and the 1-year average closing stock price.

(3) The expected term of options is derived from historical data.

(4) Volatility is based upon 50% historical and 50% implied volatility. Historic volatility is based on the weighted average between Duke and Cinergy historical volatility over the expected life using daily stock prices. Implied volatility is the average for all option contracts with a term greater than six months using the strike price closest to the stock price on the valuation date.

The 2006 Plan allows for a maximum of 15 million shares of common stock to be issued under various stock-based awards other than options and stock appreciation rights. The 1998 Plan allows for a maximum of 12 million shares of common stock to be issued under various stock-based awards. Payments for cash settled awards during the period were immaterial.

Performance Awards

Stock-based performance awards outstanding under the 1998 Plan generally vest over three years. Vesting for certain stock-based performance awards can occur in three years, at the earliest, if performance is met. Certain performance awards granted in 2006 contain market conditions based on the total shareholder return (TSR) of Duke Energy stock relative to a pre-defined peer group (relative TSR). These awards are valued using a path-dependent model that incorporates expected relative TSR into the fair value determination of Duke Energy's performance-based share awards with the adoption of SFAS No. 123(R). The model uses three year historical volatilities and correlations for all companies in the pre-defined peer group, including Duke Energy, to simulate Duke Energy's relative TSR as of the end of the performance period. For each simulation, Duke Energy's relative TSR associated with the simulated stock price at the end of the performance period plus expected dividends within the period results in a value per share for the award portfolio. The average of these simulations is the expected portfolio value per share. Actual life to date results of Duke Energy's relative TSR for each grant is incorporated within the model. Other awards not containing market conditions are measured at grant date price. Duke Energy awarded 1,610,350 shares (fair value of approximately $32 million) in the year ended December 31, 2006, 1,275,020 shares (fair value of approximately $34 million, based on the market price of Duke Energy's common stock at the grant date) in the year ended December 31, 2005, and 1,584,840 shares (fair value of approximately $34 million, based on the market price of Duke Energy's common stock at the grant date) in the year ended December 31, 2004.

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

The following table summarizes information about stock-based performance awards outstanding at December 31, 2006

	Shares	Weighted Average Grant Date Fair Value
Number of Stock-based Performance Awards:		
Outstanding at December 31, 2005	2,940,768	$ 25
Granted	1,610,350	20
Vested	(114,000)	27
Forfeited	(310,838)	26
Canceled	—	—
Outstanding at December 31, 2006	4,126,280	$ 23
Stock-based Performance Awards Expected to Vest	3,955,865	$ 23

The total fair value of the shares vested during the year ended December 31, 2006 and 2005 was approximately $3 million As of December 31, 2006, Duke Energy had approximately $31 million of future compensation cost which is expected to be recognized over a weighted-average period of 1 0 years

Phantom Stock Awards

Phantom stock awards outstanding under the 1998 Plan generally vest over periods from immediate to five years Duke Energy awarded 1,181,370 shares (fair value of approximately $34 million) based on the market price of Duke Energy's common stock at the grant dates in the year ended December 31, 2006, 1,139,880 shares (fair value of approximately $31 million) in the year ended December 31, 2005, and 1,283,220 shares (fair value of approximately $27 million) in the year ended December 31, 2004 Converted Cinergy phantom stock awards are paid in cash and are measured and recorded as liability awards

The following table summarizes information about phantom stock awards outstanding at December 31, 2006:

	Shares	Weighted Average Grant Date Fair Value
Number of Phantom Stock Awards:		
Outstanding at December 31, 2005	2,517,020	$ 25
Granted(b)	1,213,532	29
Vested	(917,441)	25
Forfeited	(200,791)	26
Canceled	—	—
Outstanding at December 31, 2006	2,612,320	$ 27
Phantom Stock Awards Expected to Vest	2,507,432	$ 27

(b) Includes 32,162 converted Cinergy awards

The total fair value of the shares vested during the years ended December 31, 2006, 2005 and 2004 was approximately $23 million, $10 million and $7 million, respectively As of December 31, 2006, Duke Energy had approximately $24 million of future compensation cost which is expected to be recognized over a weighted-average period of 3 0 years

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

Other Stock Awards

Other stock awards outstanding under the 1998 Plan generally vest over periods from three to five years. Duke Energy awarded 279,000 shares (fair value of approximately $8 million) based on the market price of Duke Energy's common stock at the grant dates in the year ended December 31, 2006, 47,000 shares (fair value of approximately $1 million) in the year ended December 31, 2005, and 169,160 shares (fair value of approximately $4 million) in the year ended December 31, 2004.

The following table summarizes information about other stock awards outstanding at December 31, 2006:

	Shares	Weighted Average Grant Date Fair Value
Number of Other Stock Awards:		
Outstanding at December 31, 2005	178,337	$ 25
Granted[(c)]	329,980	28
Vested	(71,610)	26
Forfeited	(10,200)	33
Canceled	—	—
Outstanding at December 31, 2006	426,507	$ 28
Other Stock Awards Expected to Vest	395,671	$ 28

(c) Includes 50,980 converted Cinergy awards

The total fair value of the shares vested during the years ended December 31, 2006, 2005 and 2004 was approximately $2 million, $1 million and $1 million, respectively. As of December 31, 2006, Duke Energy had approximately $8 million of future compensation cost which is expected to be recognized over a weighted-average period of 2.9 years.

21. Common Stock

During 2006, Duke Energy's $742 million of convertible debt became convertible into approximately 31.7 million shares of Duke Energy common stock due to the market price of Duke Energy common stock achieving a specified threshold for each pricing period prior to respective quarter. Holders of the convertible debt were able to exercise their right to convert on or prior to each quarter end. During 2006, approximately $632 million of debt was converted into approximately 26.7 million shares of Duke Energy common stock. At December 31, 2006, the balance of the convertible debt is approximately $110 million, which is convertible into approximately 4.7 million shares of common stock.

See Note 1 for discussion of 313 million shares of common stock issued in April 2006 as a result of the merger with Cinergy.

Effective in the third quarter 2006, the Board of Directors of Duke Energy approved a quarterly dividend increase of $0.01 per share, increasing the annual dividend to $1.28 per share.

In February 2005, Duke Energy announced plans to execute up to approximately $2.5 billion in common stock repurchases over a three year period. In May 2005, Duke Energy suspended additional repurchases, pending further assessment. At the time of suspension, Duke Energy had repurchased approximately $933 million of common stock. In the first quarter of 2006, as a result of the March 10, 2006 shareholder approval of the Cinergy merger, Duke Energy's Board of Directors authorized the repurchase of up to an additional $1 billion of common stock under the previously announced share repurchase plan. In June 2006, Duke Energy suspended additional repurchases of Duke Energy common stock under the repurchase plan due to its plan to spin off the natural gas businesses (see Note 25). Prior to the June 2006 suspension, Duke Energy repurchased 17.5 million shares for total consideration of approximately $500 million during 2006. The repurchases and corresponding commissions and other fees were recorded in Common Stockholders' Equity as a reduction in Common Stock and Additional Paid-in Capital. In October 2006, Duke Energy's Board of Directors authorized the reactivation of the share repurchase plan for Duke Energy of up to $500 million of share repurchases after the spin-off of the natural gas businesses has been completed.

On March 18, 2005, Duke Energy entered into an accelerated share repurchase transaction whereby Duke Energy repurchased and retired 30 million shares of its common stock from an investment bank at the March 18, 2005 closing price of $27.46 per share. Total consideration paid to repurchase the shares of approximately $834 million, including approximately $10 million in commissions and other fees, was recorded in Common Stockholders' Equity as a reduction in Common Stock. Additionally, Duke Energy entered into a separate open-market purchase plan on March 18, 2005 to repurchase up to an additional 20 million shares of its common stock, of which approximately 2.6 million shares were repurchased prior to the May 2005 suspension of the program at a weighted average price of $28.97.

per share As part of the accelerated share repurchase transaction, Duke Energy simultaneously entered into a forward sale contract with the investment bank that was to mature no later than November 8, 2005 Under the terms of the forward sale contract, the investment bank was required to purchase, in the open market, 30 million shares of Duke Energy common stock during the term of the contract to fulfill its obligation related to the shares it borrowed from third parties and sold to Duke Energy At settlement, Duke Energy, at its option, was required to either pay cash or issue registered or unregistered shares of its common stock to the investment bank if the investment bank's weighted average purchase price was higher than the March 18, 2005 closing price of $27 46 per share, or the investment bank was required to pay Duke Energy either cash or shares of Duke Energy common stock, at Duke Energy's option, if the investment bank's weighted average price for the shares purchased was lower than the March 18, 2005 closing price of $27 46 per share On September 22, 2005, Duke Energy, at its option, paid approximately $25 million in cash to the investment bank to settle the forward sale contract as the investment bank had repurchased the full 30 million shares in the open market and fulfilled all of its obligations The amount paid to the investment bank was based upon the difference between the investment bank's weighted average price paid for the 30 million shares purchased of $28 42 per share and the March 18, 2005 closing price of $27 46 per share Duke Energy recorded the approximately $25 million paid at settlement in Common Stockholders' Equity as a reduction in Common Stock Total consideration paid to repurchase the shares of approximately $933 million, including commissions and other fees, was recorded in Common Stockholders' Equity as a reduction in Common Stock and Additional Paid-in Capital

~~In November 2004, Duke Energy issued 18,693,000 shares of its common stock in the settlement of the forward-purchase contract component of its Equity Units issued in November~~ 2001 Under the terms of the contract, the Equity Unit holders were required to purchase stock at the time of settlement rate based on the current market price of Duke Energy's common stock at the time of the settlement with a floor and a ceiling The rate was 6231 shares of stock per Equity Unit Duke Energy received $750 million in proceeds as a result of the settlement, which was included in Proceeds from the Issuances of Common Stock and Common Stock Related to Employee Benefit Plans on the Consolidated Statement of Cash Flows

In May 2004, Duke Energy issued 22,449,000 shares of its common stock in the settlement of the forward-purchase contract component of its Equity Units issued in March 2001 Under the terms of the contract, the Equity Unit holders were required to purchase common stock at a settlement rate based on the current market price of Duke Energy's common stock at the time of settlement with a floor and a ceiling The rate was 0.6414 shares of stock per Equity Unit Duke Energy received $875 million in proceeds as a result of the settlement, which was included in Proceeds from the Issuances of Common Stock and Common Stock Related to Employee Benefit Plans on the Consolidated Statement of Cash Flows.

Duke Energy also sponsors an employee savings plan that covers substantially all U S employees In April 2004, Duke Energy stopped issuing shares under the plan and the plan began making open market purchases with cash provided by Duke Energy There were no issuances of common stock under the plan in either 2006 or 2005 Issuances of common stock under the plan were $51 million in 2004 Duke Energy also issues shares of its common stock to meet other employee benefit requirements Issuances of common stock to meet other employee benefit requirements were approximately $146 million for 2006, $39 million for 2005 and approximately $12 million for 2004

See the Consolidated Statements of Common Stockholders' Equity and Comprehensive Income (Loss) for additional equity transactions

22. Employee Benefit Plans

Duke Energy U.S. Retirement Plans. Duke Energy and its subsidiaries (including legacy Cinergy businesses) maintain qualified, non-contributory defined benefit retirement plans The plans cover most U S employees using a cash balance formula Under a cash balance formula, a plan participant accumulates a retirement benefit consisting of pay credits that are based upon a percentage (which may vary with age and years of service) of current eligible earnings and current interest credits Certain legacy Cinergy U S employees are covered under plans that use a final average earnings formula. Under a final average earnings formula, a plan participant accumulates a retirement benefit equal to a percentage of their highest 3-year average earnings, plus a percentage of the their highest 3-year average earnings in excess of covered compensation per year of participation (maximum of 35 years), plus a percentage of their highest 3-year average earnings times years of participation in excess of 35 years.

Duke Energy also maintains non-qualified, non-contributory defined benefit retirement plans which cover certain U.S executives

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

Duke Energy's policy is to fund amounts on an actuarial basis to provide assets sufficient to meet benefits to be paid to plan participants Duke Energy contributed approximately $124 million to the legacy Cinergy qualified pension plans in 2006 Duke Energy did not make any contributions to its defined benefit retirement plans in 2005 Duke Energy made voluntary contributions of $250 million in the fourth quarter of 2004

Actuarial gains and losses are amortized over the average remaining service period of the active employees The average remaining service period of active employees covered by the qualified retirement plans is 11 years The average remaining service period of active employees covered by the non-qualified retirement plans is 8 years Duke Energy determines the market-related value of plan assets using a calculated value that recognizes changes in fair value of the plan assets in a particular year on a straight line basis over the next five years Duke Energy uses a September 30 measurement date for its defined benefit retirement plans

Westcoast Canadian Retirement Plans The Westcoast benefit plans are reported separately due to actuarial assumption differences Westcoast and its subsidiaries maintain qualified and non-qualified contributory and non-contributory defined benefit (DB) and defined contribution (DC) retirement plans covering substantially all employees The DB plans provide retirement benefits based on each plan participant's years of service and final average earnings Under the DC plans, company contributions are determined according to the terms of the plan and based on each plan participant's age, years of service and current eligible earnings Westcoast also provides non-registered defined benefit supplemental pensions to all employees who retire under a defined benefit registered pension plan and whose pension is limited by the maximum pension limits under the Income Tax Act (Canada)

Westcoast's policy is to fund the DB plans on an actuarial basis and in accordance with Canadian pension standards legislation, in order to accumulate assets sufficient to meet benefits to be paid Contributions to the DC plans are determined in accordance with the terms of the plan Duke Energy made contributions to the Westcoast DB plans of approximately $44 million in 2006, $42 million in 2005 and $26 million in 2004 Duke Energy also made contributions to the DC plans of $4 million in 2006, $3 million in 2005 and $3 million in 2004.

The prior service cost and actuarial gains and losses are amortized over the average remaining service period of the active employees The average remaining service period of the active employees covered by the qualified DB retirement plans is 10 years The average remaining service period of the active employees covered by the non-qualified DB retirement plan is 14 years Westcoast uses a September 30 measurement date for its plans

Duke Energy adopted the disclosure and recognition provisions of SFAS No 158, effective December 31, 2006 The following table describes the total incremental effect of the adoption of SFAS No 158 on individual line items in the December 31, 2006 Consolidated Balance Sheet, including Accumulated Other Comprehensive Income

Incremental Effect of the Adoption of SFAS No. 158 on Individual Line Items in the Consolidated Balance Sheet As of December 31, 2006 [a]

	Duke Energy U.S.			Westcoast		
	Before Application of SFAS No. 158	Adjustment	After Application of SFAS No. 158[b]	Before Application of SFAS No. 158	Adjustment	After Application of SFAS No. 158
	(in millions)					
Accrued pension and other post-retirement liabilities[c]	$ (1,562)	$ (385)	$ (1,947)	$ (223)	$ (69)	$ (292)
Intangible assets	—	—	—	6	(6)	—
Pre-funded pension costs	697	(522)	175	—	—	—
Regulatory assets	—	595	595	—	—	—
Deferred income tax assets	—	115	115	32	27	59
Accumulated other comprehensive income, net of tax	—	197	197	61	48	109
Total Recognized	$ (865)	$ —	$ (865)	$ (124)	$ —	$ (124)

(a) Excludes approximately $7 million in accrued pension and other post-retirement liabilities, approximately $2 million in deferred income tax assets and $5 million in accumulated other comprehensive income associated with a Brazilian retirement plan

(b) Includes approximately $87 million in accrued pension and other post-retirement liabilities and $4 million in accumulated other comprehensive income related to delayed recognition provisions associated with post-employment benefits

(c) Includes approximately $89 million that is reflected in Other within Current Liabilities in the Consolidated Balance Sheets at December 31, 2006

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

Qualified Pension Plans

Components of Net Periodic Pension Costs (Income): Qualified Pension Plans

	Duke Energy U.S.			Westcoast		
	For the Years Ended December 31,					
	2006	2005	2004	2006	2005	2004
	(in millions)					
Service cost benefit earned during the year	$ 93	$ 61	$ 64	$ 13	$ 9	$ 8
Interest cost on projected benefit obligation	207	157	160	31	29	26
Expected return on plan assets	(275)	(229)	(233)	(33)	(27)	(24)
Amortization of prior service cost	(1)	(1)	(2)	1	1	—
Amortization of net transition asset	—	—	(4)	—	—	—
Curtailment (gain) / loss	—	—	(1)	—	—	—
Amortization of loss	54	35	15	10	4	3
Special termination benefit cost	2	—	—	—	—	1
Net periodic pension costs / (income)	$ 80	$ 23	$ (1)	$ 22	$ 16	$ 14

Reconciliation of Funded Status to Net Amount Recognized: Qualified Pension Plans

	Duke Energy U.S.		Westcoast	
	As of and for the Years Ended December 31,			
	2006	2005	2006	2005
	(in millions)			
Change in Projected Benefit Obligation				
Obligation at prior measurement date	$ 2,853	$ 2,693	$ 616	$ 480
Service cost	93	61	13	9
Interest cost	207	157	31	29
Actuarial losses / (gains)	42	105	20	89
Plan amendments	19	—	—	—
Participant contributions	—	—	3	3
Benefits paid	(263)	(163)	(32)	(28)
Obligation assumed from acquisition	1,872	—	—	11
Foreign currency impact	—	—	2	23
Obligation at measurement date	$ 4,823	$ 2,853	$ 653	$ 616

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

	Duke Energy U.S.		Westcoast	
	As of and for the Years Ended December 31,			
	2006	2005	2006	2005
	(in millions)			
Change in Fair Value of Plan Assets				
Plan assets at prior measurement date	$ 2,948	$ 2,477	$ 475	$ 362
Actual return on plan assets	316	384	32	63
Benefits paid	(263)	(163)	(32)	(28)
Employer contributions	124	250	45	48
Plan participants' contributions	—	—	3	3
Assets received on acquisition	1,199	—	—	10
Foreign currency impact	—	—	2	17
Plan assets at measurement date	$ 4,324	$ 2,948	$ 525	$ 475
Funded status	$ (499)	$ 95	$ (128)	$ (141)
Unrecognized net experience loss	—	655	—	122
Unrecognized prior service cost	—	(3)	—	8
Contributions between measurement date and year end	—	—	12	13
Net amount recognized	$ (499)	$ 747	$ (116)	$ 2

For the Duke Energy U S plans, the accumulated benefit obligation was $4,408 million at September 30, 2006 and $2,753 million at September 30, 2005

For Westcoast, the accumulated benefit obligation was $588 million at September 30, 2006 and $562 million at September 30, 2005

Qualified Pension Plans—Amounts Recognized in the Consolidated Balance Sheets Consist of:

	Duke Energy U.S.		Westcoast	
	As of December 31,			
	2006	2005	2006	2005
	(in millions)			
Accrued pension liability	$ (674)	$ —	$ (116)	$ (76)
Intangible asset	—	—	—	7
Pre-funded pension costs	175	747	—	—
Deferred income tax asset	—	—	—	25
Accumulated other comprehensive income	—	—	—	46
Net amount recognized	$ (499)	$ 747	$ (116)	$ 2

Table of Contents

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

As a result of the adoption of SFAS No 158, certain previously unrecognized amounts were recognized in the amounts noted above with an offset to Accumulated Other Comprehensive Income, Deferred Income Taxes and Regulatory Assets as of December 31, 2006 The table below details the components of these balances

Qualified Pension Plans—Amounts Recognized in Regulatory Assets and Accumulated Other Comprehensive Income Consist of:

	Duke Energy U.S.	Westcoast
	As of December 31, 2006	
	(in millions)	
Regulatory assets	$ 481	$ —
Accumulated other comprehensive income		
~~Deferred income tax asset~~	~~$ (50)~~	~~$ (49)~~
Net transition obligation	—	—
Prior service cost	10	8
Net actuarial loss	126	132
Net amount recognized – Accumulated other comprehensive income	$ 86	$ 91

Qualified Pension Plans—Amounts in Regulatory Assets and Accumulated Other Comprehensive Income to be Recognized in Net Periodic Pension Costs in 2007 Consist of:

	Duke Energy
	(in millions
Unrecognized (gains)/losses	$
Unrecognized prior service cost	
Net amount to be recognized	$

Amounts in the above table exclude Westcoast due to the spin-off of the natural gas businesses on January 2, 2007

Additional Information:

Qualified Pension Plans—Information for Plans with Accumulated Benefit Obligation in Excess of Plan Assets

	Duke Energy U.S.		Westcoast	
	As of December 31,			
	2006	2005	2006	2005
	(in millions)			
Projected benefit obligation	$ 1,976	$ —	$ 637	$ 602
Accumulated benefit obligation	1,688	—	576	551
Fair value of plan assets	1,302	—	511	464

Qualified Pension Plans—Assumptions Used for Pension Benefits Accounting

	Duke Energy U.S.			Westcoast		
Benefit Obligations	**2006**	**2005**	**2004**	**2006**	**2005**	**2004**
	(percentages)					
Discount rate	5.75	5 50	6 00	5.00	5.00	6.25
Salary increase	5 00	5 00	5 00	3 50	3.25	3 25
Determined Expense	**2006**	**2005**	**2004**	**2006**	**2005**	**2004**
Discount rate	5.50-6.00	6.00	6.00	5.00	6.25	6.00
Salary increase	5 00	5 00	5 00	3 25	3.25	3 25
Expected long-term rate of return on plan assets	8.50	8.50	8.50	7 25	7.50	7.50

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

For the Duke Energy U S plans the discount rate used to determine the pension obligation is based on a AA bond yield curve The yield is selected based on bonds with cash flows that match the timing and amount of the expected benefit payments under the plan. For legacy Cinergy plans, the discount rate used to determine expense reflects remeasurement as of April 1, 2006 due to the merger between Duke Energy and Cinergy

For Westcoast the discount rate used to determine the pension obligation is prescribed as the yield on Canadian corporate AA bonds at the measurement date of September 30 The yield is selected based on bonds with cash flows that match the timing and amount of the expected benefit payments under the plan

Qualified Pension Plan Assets—Duke Energy U S.:

Asset Category	Target Allocation	Percentage of Plan Assets at September 30 2006	2005
U.S. equity securities	46%	46%	46%
Non-U S equity securities	18	19	21
Debt securities	32	32	29
Real estate	4	3	4
Total	100%	100%	100%

Duke Energy U S assets for both the pension and other post retirement benefits are maintained by two Master Trusts The investment objective of the master trusts is to achieve reasonable returns on trust assets, subject to a prudent level of portfolio risk, for the purpose of enhancing the security of benefits for plan participants The asset allocation targets were set after considering the investment objective and the risk profile with respect to the trusts U S. equities are held for their high expected return. Non-U S equities, debt securities, and real estate are held for diversification Investments within asset classes are to be diversified to achieve broad market participation and reduce the impact of individual managers or investments Duke Energy regularly reviews its actual asset allocation and periodically rebalances its investments to the targeted allocation when considered appropriate

The long-term rate of return of 8 5% as of September 30, 2006 for the Duke Energy U S assets was developed using a weighted-average calculation of expected returns based primarily on future expected returns across classes considering the use of active asset managers The weighted-average returns expected by asset classes were 4 2% for U S equities, 1 8% for Non-U S equities, 2 2% for fixed income securities, and 0 3% for real estate

Qualified Pension Plan Assets—Westcoast:

Asset Category	Target Allocation	Percentage of Plan Assets at September 30 2006	2005
Canadian equity securities	30%	29%	42%
U S equity securities	15	15	11
EAFE equity securities[a]	15	16	15
Debt securities	40	40	32
Total	100%	100%	100%

(a) EAFE—Europe, Australasia, Far East

Westcoast assets for registered pension plans are maintained by a Master Trust The investment objective of the master trust is to achieve reasonable returns on trust assets, subject to a prudent level of portfolio risk, for the purpose of enhancing the security of benefits for participants The asset allocation targets were set after considering the investment objective and the risk profile with respect to the trust Canadian equities are held for their high expected return Non-Canadian equities are held for their high expected return as well as diversification relative to Canadian equities and debt securities Debt securities are also held for diversification

The long-term rate of return of 7 25% as of September 30, 2006 for the Westcoast assets was developed using a weighted-average calculation of expected returns based primarily on future expected returns across classes considering the use of active asset managers

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

The weighted-average returns expected by asset classes were 2.5% for Canadian equities, 1.3% for U.S. equities, 1.4% for Europe, Australasia and Far East equities, and 2.0% for fixed income securities.

The following benefit payments, which reflect expected future service, as appropriate, as expected to be paid over the next five years and thereafter:

Qualified Pension Plans—Expected Benefit Payments

	U.S. Plans	Westcoast Plans
	(in millions)	
Years Ended December 31,		
2007	$ 311	$ 31
2008	309	31
2009	323	32
2010	342	33
2011	377	34
2012 – 2016	2,101	201

Non-Qualified Pension Plans

Components of Net Periodic Pension Costs: Non-Qualified Pension Plans

	Duke Energy U.S.			Westcoast		
	For the Years Ended December 31,					
	2006	2005	2004	2006	2005	2004
	(in millions)					
Service cost benefit earned during the year	$ 2	$ 1	$ 2	$ 1	$ 1	$ —
Interest cost on projected benefit obligation	8	5	6	4	4	4
Expected return on plan assets	—	—	—	—	—	—
Amortization of prior service cost	1	1	1	—	—	—
Amortization of net transition (asset)/liability	—	1	1	—	—	—
Curtailment (gain) / loss	—	—	1	—	—	—
Amortization of loss	—	—	—	1	—	—
Net periodic pension costs / (income)	$ 11	$ 8	$ 11	$ 6	$ 5	$ 4

Reconciliation of Funded Status to Net Amount Recognized: Non-Qualified Pension Plans

	Duke Energy U.S.		Westcoast	
	As of and for the Years Ended December 31,			
	2006	2005	2006	2005
	(in millions)			
Change in Projected Benefit Obligation				
Obligation at prior measurement date	$ 86	$ 86	$ 84	$ 66
Service cost	2	1	1	1
Interest cost	8	5	4	4
Actuarial losses / (gains)	4	2	3	14
Plan amendments	(2)	—	—	—
Participant contributions	—	—	—	—
Benefits paid	(36)	(8)	(4)	(3)
Obligation assumed from acquisition	137	—	—	—
Foreign currency impact	—	—	—	2
Obligation at measurement date	$ 199	$ 86	$ 88	$ 84

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

	Duke Energy U.S.		Westcoast	
	As of and for the Years Ended December 31,			
	2006	2005	2006	2005
	(in millions)			
Change in Fair Value of Plan Assets				
Plan assets at prior measurement date	$ —	$ —	$ —	$ —
Actual return on plan assets	—	—	—	—
Benefits paid	(36)	(8)	(4)	(3)
Employer contributions	36	8	4	3
Plan participants' contributions	—	—	—	—
Assets received on acquisition	—	—	—	—
Foreign currency impact	—	—	—	—
Plan assets at measurement date	$ —	$ —	$ —	$ —
Funded status	$ (199)	$ (86)	$ (88)	$ (84)
Unrecognized net experience loss	—	(7)	—	23
Unrecognized prior service cost	—	8	—	—
Contributions between measurement date and year end	21	2	2	1
Accrued pension liability	$ (178)	$ (83)	$ (86)	$ (60)

For the Duke Energy U.S. plans, the accumulated benefit obligation was $184 million at September 30, 2006 and $79 million at September 30, 2005

For Westcoast, the accumulated benefit obligation was $83 million at September 30, 2006 and $82 million at September 30, 2005

Non-Qualified Pension Plans—Amounts Recognized in the Consolidated Balance Sheets Consist of:

	Duke Energy U.S.		Westcoast	
	As of December 31,			
	2006	2005	2006	2005
	(in millions)			
Accrued pension liability[(a)]	$ (178)	$ (83)	$ (86)	(81)
Pre-funded pension costs	—	—	—	—
Accumulated other comprehensive income	—	—	—	21
Net amount recognized	$ (178)	$ (83)	$ (86)	$ (60)

(a) Duke Energy U.S. includes approximately $41 million and Westcoast includes approximately $6 million recognized in Other within Current Liabilities on the Consolidated Balance Sheets as of December 31, 2006

As a result of the adoption of SFAS No. 158, certain previously unrecognized amounts were recognized in the amounts noted above with an offset to Accumulated Other Comprehensive Income, Deferred Income Taxes and Regulatory Assets as of December 31, 2006. The table below details the components of these balances

Non-Qualified Pension Plans—Amounts Recognized in Regulatory Assets and Accumulated Other Comprehensive Income

Consist of:

	Duke Energy U.S.	Westcoast
	As of December 31, 2006	
	(in millions)	
Regulatory assets	$ 4	$ —
Accumulated other comprehensive income		
Deferred income tax liability (asset)	$ 1	$ (9)
Net transition obligation	—	—
Prior service cost	5	—
Net actuarial loss	(7)	25

Net amount recognized- Accumulated other comprehensive income	$ (1)	$ 16

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

Non-Qualified Pension Plans—Amounts in Regulatory Assets and Accumulated Other Comprehensive Income to be Recognized in Net Periodic Pension Costs in 2007 Consist of:

	Duke Energy
	(in millions
Unrecognized (gains)/losses	$
Unrecognized prior service cost	
Net amount to be recognized	$

Amounts in the above table exclude Westcoast due to the spin-off of the natural gas businesses on January 2, 2007.

Additional Information:

Non-Qualified Pension Plans—Information for Plans with Accumulated Benefit Obligation in Excess of Plan Assets

	Duke Energy U.S.		Westcoast	
	As of December 31,			
	2006	2005	2006	2005
	(in millions)			
Projected benefit obligation	$ 199	$ 86	$ 88	$ 84
Accumulated benefit obligation	184	79	83	82
Fair value of plan assets	—	—	—	—

Non-Qualified Pension Plans—Assumptions Used for Pension Benefits Accounting

	Duke Energy U.S.			Westcoast		
Benefit Obligations	**2006**	**2005**	**2004**	**2006**	**2005**	**2004**
			(percentages)			
Discount rate	5.75	5.50	6.00	5.00	5.00	6.25
Salary increase	5.00	5.00	5.00	3.50	3.25	3.25
Determined Expense	**2006**	**2005**	**2004**	**2006**	**2005**	**2004**
Discount rate	5.50-6.00	6.00	6.00	5.00	6.25	6.00
Salary increase	5.00	5.00	5.00	3.25	3.25	3.25

For the Duke Energy U.S. plans the discount rate used to determine the pension obligation is based on a AA bond yield curve. The yield is selected based on bonds with cash flows that match the timing and amount of the expected benefit payments under the plan. For legacy Cinergy plans, the discount rate used to determine expense reflects remeasurement as of April 1, 2006 due to the merger between Duke Energy and Cinergy.

For Westcoast the discount rate used to determine the pension obligation is prescribed as the yield on Canadian corporate AA bonds at the measurement date of September 30. The yield is selected based on bonds with cash flows that match the timing and amount of the expected benefit payments under the plan.

Non-Qualified Plans—Expected Benefit Payments

	U.S. Plans	Westcoast Plans
	(in millions)	
Years Ended December 31,		
2007	$ 41	$ 5
2008	16	5
2009	20	5
2010	16	5
2011	16	5
2012 – 2016	66	26

PART II

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

Duke Energy also sponsors employee savings plans that cover substantially all U S employees Most employees participate in a matching contribution formula where Duke Energy provides a matching contribution generally equal to 100% of before-tax employee contributions, of up to 6% of eligible pay per pay period Duke Energy expensed employer matching contributions of $75 million in 2006, $61 million in 2005 and $57 million in 2004. Dividends on Duke Energy shares held by the savings plans are charged to retained earnings when declared and shares held in the plans are considered outstanding in the calculation of basic and diluted earnings per share

Other Post-Retirement Benefit Plans

Duke Energy U.S Other Post-Retirement Benefits Duke Energy and most of its subsidiaries provide some health care and life insurance benefits for retired employees on a contributory and non-contributory basis Employees are eligible for these benefits if they have met age and service requirements at retirement, as defined in the plans

These benefit costs are accrued over an employee's active service period to the date of full benefits eligibility The net unrecognized transition obligation is amortized over approximately 20 years Actuarial gains and losses are amortized over the average remaining service period of the active employees. The average remaining service period of the active employees covered by the plan is 13 years.

Westcoast Other Post-Retirement Benefits. Westcoast provides health care and life insurance benefits for retired employees on a non-contributory basis Employees are eligible for these benefits if they have met age and service requirements at retirement, as defined in the plans Effective December 31, 2003, a new plan was implemented for all non bargaining employees and the majority of bargaining employees The new plan will apply for employees retiring on and after January 1, 2006 The new plan is predominantly a defined contribution plan as compared to the existing defined benefit program

Other post-retirement benefit costs are accrued over an employee's active service period to the date of full benefits eligibility Actuarial gains and losses are amortized over the average remaining service period of the active employees covered by the plans. The average remaining service period of the active employees is 18 years

Components of Net Periodic Other Post-Retirement Benefit Costs

	Duke Energy U.S.			Westcoast		
	For the Years Ended December 31,					
	2006	2005	2004	2006	2005	2004
	(in millions)					
Service cost benefit earned during the year	$ 10	$ 6	$ 5	$ 4	$ 3	$ 3
Interest cost on accumulated post-retirement benefit obligation	56	45	47	7	6	5
Expected return on plan assets	(17)	(18)	(19)	—	—	—
Amortization of prior service cost	1	1	1	(1)	(1)	(1)
Amortization of net transition liability	16	16	16	—	—	—
Amortization of loss	10	7	8	2	1	1
Net periodic other post-retirement benefit costs	$ 76	$ 57	$ 58	$ 12	$ 9	$ 8

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

Reconciliation of Funded Status to Accrued Other Post-Retirement Benefit Costs

	Duke Energy U.S.		Westcoast	
	As of and for the Years Ended December 31,			
	2006	2005	2006	2005
	(in millions)			
Change in Benefit Obligation				
Accumulated post-retirement benefit obligation at prior measurement date	$ 791	$ 782	$ 117	$ 86
Service cost	10	6	4	3
Interest cost	56	45	7	6
Plan participants' contributions	25	21	—	—
Actuarial (gain) / loss	(4)	17	(34)	21
Benefits paid	(88)	(80)	(4)	(3)
Accrued RDS subsidy	4	—	—	—
Obligation assumed from acquisition	470	—	—	—
Foreign currency impact	—	—	1	4
Accumulated post-retirement benefit obligation at measurement date	$ 1,264	$ 791	$ 91	$ 117

	Duke Energy U.S.		Westcoast	
	As of and for the Years Ended December 31,			
	2006	2005	2006	2005
	(in millions)			
Change in Fair Value of Plan Assets				
Plan assets at prior measurement date	$ 242	$ 243	$ —	$ —
Actual return on plan assets	12	21	—	—
Benefits paid	(88)	(80)	(4)	(3)
Employer contributions	46	37	4	3
Plan participants' contributions	25	21	—	—
Plan assets at measurement date	$ 237	$ 242	$ —	$ —
Funded status	$ (1,027)	$ (549)	$ (91)	$ (117)
Employer contributions made after measurement date	17	10	1	1
Unrecognized net experience loss	—	209	—	49
Unrecognized prior service cost	—	1	—	(11)
Unrecognized transition obligation	—	111	—	—
Accrued other post-retirement benefit costs recognized	$ (1,010)	$ (218)	$ (90)	$ (78)

Other Post-Retirement Benefit Plans—Amounts Recognized in the Consolidated Balance Sheets Consist of:

	Duke Energy U.S.		Westcoast	
	As of December 31,			
	2006	2005	2006	2005
	(in millions)			
Accrued other post-retirement liability(a)	$ (1,010)	$ (218)	$ (90)	$ (78)
Intangible asset	—	—	—	—
Pre-funded pension costs	—	—	—	—
Net amount recognized	$ (1,010)	$ (218)	$ (90)	$ (78)

(a) Duke Energy U.S. includes approximately $26 million and Westcoast includes approximately $4 million recognized in Other within Current Liabilities on the Consolidated Balance Sheets as of December 31, 2006

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

As a result of the adoption of SFAS No 158, certain previously unrecognized amounts were recognized in the amounts noted above with an offset to Accumulated Other Comprehensive Income, Deferred Income Taxes and Regulatory Assets as of December 31, 2006 The table below details the components of these balances

Other Post-Retirement Benefit Plans—Amounts Recognized in Regulatory Assets and Accumulated Other Comprehensive Income Consist of:

	Duke Energy U.S.	Westcoast
	As of December 31, 2006	
	(in millions)	
Regulatory Assets	$ 111	$ —
Accumulated other comprehensive income		
Deferred income tax asset	$ (66)	$ (1)
Net Transition Obligation	95	
Prior Service Cost	(2)	(11)
Net Actuarial Loss	89	14
Net amount recognized—Accumulated other comprehensive income	$ 116	$ 2

Other Post Retirement Benefit Plans—Amounts in Regulatory Assets and Accumulated Other Comprehensive Income to be Recognized in Net Periodic Other Post-Retirement Benefit Costs in 2007 Consist of:

	Duke Energy
	(in millions
Unrecognized Transition (Asset)/Liability	$
Unrecognized (Gains)/Losses	
Unrecognized Prior Service Cost	
Net amount to be recognized	$

Amounts in the above table exclude Westcoast due to the spin-off of the natural gas businesses on January 2, 2007

For measurement purposes, plan assets were valued as of September 30 for both the Duke Energy U S and Westcoast plans In May 2004, the FASB staff issued FSP No FAS 106-2 The Modernization Act introduced a prescription drug benefit under Medicare as well as a federal subsidy to sponsors of retiree health care benefit plans The FSP provides guidance on the accounting for the subsidy Duke Energy adopted this FSP and retroactively applied this FSP as of the date of issuance for its U S plan As a result of anticipated prescription drug subsidy, the accumulated post-retirement benefit obligation had a one time decrease of $96 million in 2004 The after-tax effect on net periodic post-retirement benefit cost was a decrease of $8 million in 2006, $7 million in 2005 and $12 million for 2004 The actuarial gain included in the change in benefit obligation of $134 million in 2004 is primarily due to the recognition of anticipated employer savings as a result of Medicare Part D FSP No FAS 106-2 provides guidance that the effect of the federal subsidy should be recognized as an actuarial gain Duke Energy has recognized an approximate $5 million subsidy receivable, which is included in Receivables on the Consolidated Balance Sheets

Assumptions Used for Other Post-Retirement Benefits Accounting

	Duke Energy U.S.			Westcoast		
Determined Benefit Obligations	**2006**	**2005**	**2004**	**2006**	**2005**	**2004**
			(percentages)			
Discount rate	5.75	5.50	6.00	5.00	5.00	6.25
Salary increase	5 00	5 00	5 00	3.50	3 25	3 25

	Duke Energy U.S.			Westcoast		
Determined Expense	**2006**	**2005**	**2004**	**2006**	**2005**	**2004**
Discount rate	5.50-6.00	6.00	6.00	5.00	6.25	6.00
Salary increase	5 00	5 00	5 00	3 25	3 25	3 25
Expected long-term rate of return on plan assets	5.53-8.50	8.50	8.50	—	—	—
Assumed tax rate[a]	35 0	35.0	35 0	—	—	—

(a) Applicable to the health care portion of funded post-retirement benefits

Table of Contents

PART II

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

For the Duke Energy U S plans the discount rate used to determine the post-retirement obligation is based on a AA bond yield curve The yield is selected based on bonds with cash flows that match the timing and amount of the expected benefit payments under the plan For legacy Cinergy plans, the discount rate used to determine expense reflects remeasurement as of April 1, 2006 due to the merger between Duke Energy and Cinergy

For Westcoast the discount rate used to determine the post-retirement obligation is prescribed as the yield on Canadian corporate AA bonds at the measurement date of September 30 The yield is selected based on bonds with cash flows that match the timing and amount of the expected benefit payments under the plan

Other Post-Retirement Plan Assets—Duke Energy U.S.:

Asset Category	Target Allocation	Percentage of Plan Assets at September 30 2006	2005
U.S. equity securities	46%	46%	46%
Non-U S equity securities	18	19	21
Debt securities	32	32	29
Real estate	4	3	4
Total	100%	100%	100%

Duke Energy U S assets for both the pension and other post-retirement benefits are maintained by two Master Trusts The investment objective of the trusts is to achieve reasonable returns on trust assets, subject to a prudent level of portfolio risk, for the purpose of enhancing the security of benefits for plan participants The asset allocation targets were set after considering the investment objective and the risk profile with respect to the trusts U S equities are held for their high expected return. Non-U S equities, debt securities, and real estate are held for diversification Investments within asset classes are to be diversified to achieve broad market participation and reduce the impact of individual managers or investments Duke Energy regularly reviews its actual asset allocation and periodically rebalances its investments to the targeted allocation when considered appropriate The long-term rate of return of 8.5% as of September 30, 2006 for the Duke Energy U S assets was developed using a weighted-average calculation of expected returns based primarily on future expected returns across asset classes considering the use of active asset managers The weighted-average returns expected by asset classes were 4 2% for U S equities, 1 8% for Non-U S equities, 2 2% for fixed income securities, and 0 3% for real estate

Duke Energy also invests other post-retirement assets in the Duke Energy Corporation Employee Benefits Trust (VEBA I) and the Duke Energy Corporation Post-Retirement Medical Benefits Trust (VEBA II) The investment objective of the VEBA's is to achieve sufficient returns on trust assets, subject to a prudent level of portfolio risk, for the purpose of promoting the security of plan benefits for participants The VEBA trusts are passively managed VEBA I has a target allocation of 30% U S equities, 45% fixed income securities and 25% cash VEBA II has a target allocation of 50% U S equities and 50% fixed income securities

Assumed Health Care Cost Trend Rates [a]

	Duke Energy U.S.					
		Medical Trend Rate				
		Not Medicare Eligible	Medicare Eligible	Prescription Drug Trend Rate	Westcoast	
	2006	2005		2006	2006	2005
Health care cost trend rate assumed for next year	8.50%	8.50%	11.50%	13.00%	8.0%	7.00%
Rate to which the cost trend is assumed to decline (the ultimate trend rate)	4.75%	5.50%	5.50%	4.75%	5.00%	5.00%
Year that the rate reaches the ultimate trend rate	2013	2009	2012	2022	2009	2008

(a) Health care cost trend rates for 2006 include prescription drug trend rates due to the effect of the Modernization Act

Table of Contents

PART II

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

Sensitivity to Changes in Assumed Health Care Cost Trend Rates Duke Energy U.S. Plans (millions)

	1-Percentage-Point Increase	1-Percentage-Point Decrease
Effect on total service and interest costs	$ 6	$ (5)
Effect on post-retirement benefit obligation	86	(75)

Sensitivity to Changes in Assumed Health Care Cost Trend Rates Westcoast Plans (millions)

	1-Percentage-Point Increase	1-Percentage-Point Decrease
Effect on total service and interest costs	$ 2	$ (1)
Effect on post-retirement benefit obligation	6	(5)

Duke Energy and Westcoast expect to make the future benefit payments, which reflect expected future service, as appropriate Duke Energy expects to receive future subsidies under Medicare Part D The following benefit payments and subsidies are expected to be paid (or received) over each of the next five years and thereafter

Other Post-Retirement Plan—Expected Benefit Payments and Subsidies (in millions)

	U.S. Plan Payments	U.S. Plan Expected Subsidies	Westcoast Plans
		(in millions)	
2007	$ 77	$ 7	$ 4
2008	81	7	4
2009	84	8	4
2010	88	8	4
2011	92	9	4
2012 – 2016	491	48	23

23. Variable Interest Entities

Power Sale Special Purpose Entities (SPEs) In accordance with FIN 46, Duke Energy consolidates two SPEs that have individual power sale agreements with Central Maine Power Company (CMP) for approximately 45 megawatts (MW) of capacity, ending in 2009, and 35 MW of capacity, ending in 2016 In addition, these SPEs have individual power purchase agreements with Cinergy Capital & Trading, Inc (Capital & Trading) to supply the power Capital & Trading also provides various services, including certain credit support facilities As a result of the consolidation of these two SPEs, approximately $171 million of notes receivable (which are included in Receivables on the Consolidated Balance Sheets), $160 million of non-recourse debt (which is included in Long-Term Debt on the Consolidated Balance Sheets), and miscellaneous other assets and liabilities are included on Duke Energy's Consolidated Balance Sheets The debt was incurred by the SPEs to finance the buyout of the existing power contracts that CMP held with the former suppliers The notes receivable is comprised of two separate notes with one counterparty, whose credit rating is BBB The cash flows from the notes receivable are designed to repay the debt The first note receivable, with a December 31, 2006 balance of $62 million, bears an effective interest rate of 7.81 % and matures in August 2009 The second note receivable, with a balance of $109 million as of December 31, 2006, bears an effective interest rate of 9.23 % and matures in December 2016

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

The following table reflects the maturities of the Notes Receivable as of December 31, 2006:

Notes Receivable Maturities

	(in millions)
2007	$ 25
2008	29
2009	24
2010	8
2011	10
Thereafter	75
Total	$ 171

Subsidiary Trust Preferred Securities. In 2001, Cinergy issued approximately $316 million notional amount of 6 9 % trust preferred securities, due February 2007 The trust preferred securities were issued through a trust whose common stock was 100 % owned by Cinergy The trust loaned the proceeds from the issuance of the securities to Cinergy in exchange for a note payable to the trust Each Unit receives quarterly cash payments of 6 9 % per annum of the notional amount, which represents a trust preferred security dividend The trust's ability to pay dividends on the trust preferred securities is solely dependent on its receipt of interest payments from Cinergy on the note payable However, Cinergy has fully and unconditionally guaranteed the trust preferred securities The trust preferred securities are not included in Duke Energy's Balance Sheets In addition, the note payable owed to the trust, which amounts to approximately $326 million at December 31, 2006, is included in Current Maturities of Long-Term Debt on the Consolidated Balance Sheets In February 2007, these trust preferred securities were redeemed on their scheduled maturity date and the note payable was settled

Accounts Receivable Securitization. During 2002, Duke Energy Ohio, Duke Energy Indiana and Duke Energy Kentucky entered into an agreement to sell certain of their accounts receivable and related collections through Cinergy Receivables, a bankruptcy remote, special purpose entity Cinergy Receivables is a wholly owned limited liability company of Cinergy As a result of the securitization, Duke Energy Ohio, Duke Energy Indiana and Duke Energy Kentucky sell, on a revolving basis, nearly all of their retail accounts receivable and related collections The securitization transaction was structured to meet the criteria for sale treatment under SFAS No 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities," (SFAS No 140) and accordingly Duke Energy does not consolidate Cinergy Receivables and the transfers of receivables are accounted for as sales

The proceeds obtained from the sales of receivables are largely cash but do include a subordinated note from Cinergy Receivables for a portion of the purchase price (typically approximates 25 % of the total proceeds) The note, which amounts to approximately $210 million at December 31, 2006, is subordinate to senior loans that Cinergy Receivables obtains from commercial paper conduits controlled by unrelated financial institutions Cinergy Receivables provides credit enhancement related to senior loans in the form of over-collateralization of the purchased receivables However, the over-collateralization is calculated monthly and does not extend to the entire pool of receivables held by Cinergy Receivables at any point in time. As such, these senior loans do not have recourse to all assets of Cinergy Receivables These loans provide the cash portion of the proceeds paid to Duke Energy Ohio, Duke Energy Indiana and Duke Energy Kentucky

This subordinated note is a retained interest (right to receive a specified portion of cash flows from the sold assets) under SFAS No 140 and is classified within Receivables in the accompanying Consolidated Balance Sheets at December 31, 2006 In addition, Duke Energy's investment in Cinergy Receivables constitutes a purchased beneficial interest (purchased right to receive specified cash flows, in our case residual cash flows), which is subordinate to the retained interests held by Duke Energy Ohio, Duke Energy Indiana and Duke Energy Kentucky

The carrying values of the retained interests are determined by allocating the carrying value of the receivables between the assets sold and the interests retained based on relative fair value The key assumptions used in estimating the fair value for 2006 were an anticipated credit loss ratio of 0 7%, a discount rate of 7 4% and a receivable turnover rate of 12 0% Because (a) the receivables generally turnover in less than two months, (b) credit losses are reasonably predictable due to the broad customer base and lack of significant concentration, and (c) the purchased beneficial interest is subordinate to all retained interests and thus would absorb losses first, the allocated bases of the subordinated notes are not materially different than their face value. The hypothetical effect on the fair value of the retained interests assuming both a 10% and a 20% unfavorable variation in credit losses or discount rates is not material due to the short turnover of receivables and historically low credit loss history Interest accrues to Duke Energy Ohio, Duke Energy Indiana and Duke Energy Kentucky on the retained interests using the accretable yield method, which generally approximates the stated rate on the notes since the allocated basis and the face value are nearly equivalent. Duke Energy records income from Cinergy Receivables in a similar manner An impairment charge is recorded against the carrying value of both the retained interests and purchased beneficial interest whenever it is determined that an other-than-temporary impairment has occurred (which is unlikely unless credit losses on the receivables far exceed the anticipated level)

Duke Energy Ohio retains servicing responsibilities for its role as a collection agent on the amounts due on the sold receivables However, Cinergy Receivables assumes the risk of collection on the purchased receivables without recourse to Duke Energy Ohio, Duke Energy Indiana and Duke Energy Kentucky in the event of a loss While no direct recourse to Duke Energy Ohio, Duke Energy Indiana and Duke Energy Kentucky exists, these entities risk loss in the event collections are not sufficient to allow for full recovery of their retained interests No servicing asset or liability is recorded since the servicing fee paid to Duke Energy Ohio approximates a market rate.

The following table shows the gross and net receivables sold, retained interests, purchased beneficial interest, sales, and cash flows during the period from the date of acquisition (April 1, 2006) through December 31, 2006:

	December 31, 2006
	(in millions)
Receivables sold as of December 31, 2006	$ 573
Less: Retained interests	210
Net receivables sold as of December 31, 2006	$ 363
Purchased beneficial interest	$ 20
Sales from April 1, 2006 through December 31, 2006	
Receivables sold	$ 3,546
Loss recognized on sale	49
Cash flows from April 1, 2006 through December 31, 2006	
Cash proceeds from sold receivables	$ 3,465
Collection fees received	2
Return received on retained interests	23

Cash flows from the sale of receivables for the period from the date of acquisition through December 31. 2006 are reflected within Operating Activities on the Consolidated Statements of Cash Flows

24. Other Income and Expenses, net

The components of Other Income and Expenses, net on the Consolidated Statements of Operations for the years ended December 31, 2006, 2005 and 2004 are as follows:

	For the years ended December 31,		
	2006	2005	2004
		(in millions)	
Income/(Expense)			
Interest income	$ 190	$ 75	$ 71
Foreign exchange gains (losses)	8	(9)	22
Deferred returns and AFUDC	43	17	16
Realized and unrealized mark-to-market impact on discontinued hedges	(19)	(64)	—
Income related to a distribution from an investment at Crescent	—	45	—
Other	59	41	38
Total	$ 281	$ 105	$ 147

25. Subsequent Events

The spin-off of the natural gas businesses was effective January 2. 2007 The new natural gas company, which is named Spectra Energy, principally consists of Duke Energy's Natural Gas Transmission business segment, which includes Union Gas, and also includes

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

Duke Energy's 50% ownership interest in DEFS Approximately $20 billion of assets, $13 billion of liabilities (which includes approximately $8 6 billion of debt issued by Spectra Energy Capital and its consolidated subsidiaries), and $7 billion of common stockholders' equity were distributed from Duke Energy as of the date of the spin-off. Assets and liabilities of entities included in the spin-off of Spectra Energy were transferred from Duke Energy on a historical cost basis on the date of the spin-off transaction As a result of the spin-off transaction, on January 2, 2007, in lieu of adjusting the conversion ratio of the convertible debt, Duke Energy issued approximately 2 4 million shares of Spectra Energy common stock to holders of Duke Energy's convertible senior notes due 2023, consistent with the terms of the debt agreements The issuance of Spectra Energy shares to the convertible debt holders is expected to result in a pretax charge in the range of $20 million to $30 million in Duke Energy's 2007 consolidated statement of operations The historical results of the natural gas businesses are expected to be treated as discontinued operations at Duke Energy in future periods beginning with the first quarter of 2007 The primary businesses remaining in Duke Energy post-spin are the U.S Franchised Electric and Gas business segment, the Commercial Power business segment, the International Energy business segment and Duke Energy's effective 50% interest in the Crescent JV.

For information on other subsequent events, see Notes 1, 2, 3, 4, 12, 17, 18 and 23.

26. Quarterly Financial Data (Unaudited)

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
	(In millions, except per share data)				
2006[a]					
Operating revenues	$ 3,106	$ 3,865	$ 4,143	$ 4,070	$ 15,184
Operating income	818	738	1,203	409	3,168
Net income	358	355	763	387	1,863
Earnings available for common stockholders	358	355	763	387	1,863
Earnings per share:					
Basic[b]	$ 0.39	$ 0.29	$ 0.61	$ 0.31	$ 1.59
Diluted[b]	$ 0 37	$ 0 28	$ 0 60	$ 0 31	$ 1 57
2005[a]					
Operating revenues	$ 5,218	$ 5,156	$ 2,894	$ 3,029	$ 16,297
Operating income	717	775	1,520	594	3,606
Net income	868	309	41	606	1,824
Earnings available for common stockholders	866	307	38	601	1,812
Earnings per share:					
Basic[b]	$ 0.91	$ 0.33	$ 0.04	$ 0.65	$ 1.94
Diluted[b]	$ 0 88	$ 0 32	$ 0 04	$ 0 63	$ 1 88

(a) Operating revenues and operating income for quarterly periods in 2006 and 2005 have changed from prior filings as a result of the classification of DEM from continuing operations to discontinued operations for all periods presented

(b) Quarterly EPS amounts are meant to be stand-alone calculations and are not always additive to full-year amount due to rounding.

During the first quarter of 2006, Duke Energy recorded the following unusual or infrequently occurring item: an approximate $24 million pre-tax gain on the settlement of a customer's transportation contract (see Note 2)

During the second quarter of 2006, Duke Energy recorded the following unusual or infrequently occurring items: approximately $55 million pre-tax charge related to voluntary and involuntary severance as a result of the merger with Cinergy (see Note 12); an approximate $55 million pre-tax other-than-temporary impairment charge related to International Energy's investment in Campeche (see Note 12) and the issuance of approximately 313 million shares of common stock in connection with the merger with Cinergy (see Note 1).

During the third quarter of 2006, Duke Energy recorded the following unusual or infrequently occurring items: an approximate $246 million pre-tax gain on the sale of an effective 50% interest in the Crescent JV (see Note 2); and an approximate $40 million additional gain on the sale of DENA's assets to LS Power as a result of LS Power obtaining certain regulatory approvals (see Note 13)

During the fourth quarter of 2006, Duke Energy recorded the following unusual or infrequently occurring items: an approximate $65 million pre-tax contract settlement negotiation reserve (see Note 17); an approximate $100 million pre-tax charge to establish a settlement reserve related to the Citrus litigation (see Note 17); approximately $75 million of tax benefits (see Note 6); an approximate $25 million pre-tax gain on the sale of CMT (see Note 13); and an approximate $28 million pre-tax impairment charge at International Energy as a result of the pending sale of operations in Bolivia (see Note 12).

DUKE ENERGY CORPORATION

Notes To Consolidated Financial Statements—(Continued)

During the first quarter of 2005, Duke Energy recorded the following unusual or infrequently occurring items: an approximate $0 9 billion (net of minority interest of approximately $0 3 billion) pre-tax gain on sale of DEFS' wholly-owned subsidiary, Texas Eastern Products Pipeline Company, LLC (see Note 2); an approximate $100 million pre-tax gain on sale of Duke Energy's limited partner interest in TEPPCO Partners, L P (see Note 2); an approximate $21 million pre-tax gain on sale of DENA's partially completed Grays Harbor power plant in Washington State (see Note 2); an approximate $230 million of unrealized pre-tax losses on certain 2005 and 2006 derivative contracts hedging Field Services commodity price risk which were discontinued as cash flow hedges as a result of the anticipated deconsolidation of DEFS by Duke Energy (see Note 2). and an approximate $30 million mutual liability adjustment related to Bison which was an immaterial correction of an accounting error related to prior periods

During the third quarter of 2005, Duke Energy recorded the following unusual or infrequently occurring items: an approximate $1 3 billion pre-tax charge for the impairment of assets and the discontinuance of hedge accounting for certain positions at DENA, as a result of the decision to exit substantially all of DENA's remaining assets and contracts outside the Midwestern United States and certain contractual positions related to the Midwestern Assets (see Note 13); an approximate $575 million pre-tax gain associated with the transfer of 19 7% of Duke Energy's interest in DEFS to ConocoPhillips, Duke Energy's co-equity owner in DEFS, which reduced Duke Energy's ownership interest in DEFS from 69 7% to 50% (see Note 2); an approximate $105 million of unrealized and realized pre-tax losses on certain 2005 and 2006 derivative contracts hedging Field Services commodity price risk which were discontinued as cash flow hedges as a result of the deconsolidation of DEFS by Duke Energy (see Note 2); and approximately $90 million of gains at Crescent due primarily to income related to a distribution from an interest in a portfolio of office buildings and a large land sale

During the fourth quarter of 2005, Duke Energy recorded the following unusual or infrequently occurring items: pre-tax gain of approximately $380 million, which reverses a portion of the third quarter DENA impairment, attributable to the planned asset sales to LS Power; and pre-tax losses of approximately $475 million for portfolio exit costs including severance, retention and other transaction costs at DENA (see Note 13)

PART II

DUKE ENERGY CORPORATION

SCHEDULE II—VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

	Balance at Beginning of Period	Additions [c]: Charged to Expense	Additions [c]: Charged to Other Accounts	Deductions[a]	Balance at End of Period
			(In millions)		
December 31, 2006:					
Injuries and damages	$ 1,216	$ 7	$ 10	$ 49	$ 1,184
Allowance for doubtful accounts	127	38	21	92	94
Other[b]	896	468	287	532	1,119
	$ 2,239	$ 513	$ 318	$ 673	$ 2,397
December 31, 2005:					
Injuries and damages	$ 1,269	$ 4	$ —	$ 57	$ 1,216
Allowance for doubtful accounts	135	33	10	51	127
Other[b]	905	336	77	422	896
	$ 2,309	$ 373	$ 87	$ 530	$ 2,239
December 31, 2004:					
Injuries and damages	$ 1,319	$ 8	$ 2	$ 60	$ 1,269
Allowance for doubtful accounts	280	77	4	226	135
Other[b]	1,162	245	96	598	905
	$ 2,761	$ 330	$ 102	$ 884	$ 2,309

(a) Principally cash payments and reserve reversals.

(b) Principally insurance related reserves at Bison, uncertain tax provisions, litigation and other reserves, included in Other Current Liabilities, or Deferred Credits and Other Liabilities on the Consolidated Balance Sheets.

(c) 2006 balances include balances and activity related to Duke Energy's merger with Cinergy in April 2006.

PART II

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure.

None

Item 9A. Controls and Procedures.

Disclosure Controls and Procedures

Disclosure controls and procedures are controls and other procedures that are designed to ensure that information required to be disclosed by Duke Energy in the reports it files or submits under the Securities Exchange Act of 1934 (Exchange Act) is recorded, processed, summarized, and reported, within the time periods specified by the Securities and Exchange Commission's (SEC) rules and forms

Disclosure controls and procedures include, without limitation, controls and procedures designed to provide reasonable assurance that information required to be disclosed by Duke Energy in the reports it files or submits under the Exchange Act is accumulated and communicated to management, including the Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Under the supervision and with the participation of management, including the Chief Executive Officer and Chief Financial Officer, Duke Energy has evaluated the effectiveness of its disclosure controls and procedures (as such term is defined in Rule 13a-15(e) and 15d-15(e) under the Exchange Act) as of December 31, 2006, and, based upon this evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that these controls and procedures are effective in providing reasonable assurance that information requiring disclosure is recorded, processed, summarized, and reported within the timeframe specified by the SEC's rules and forms

Changes in Internal Control over Financial Reporting

Under the supervision and with the participation of management, including the Chief Executive Officer and Chief Financial Officer, Duke Energy has evaluated changes in internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) that occurred during the fiscal quarter ended December 31, 2006 and, other than the Duke Energy and Cinergy merger discussed below, found no change that has materially affected, or is reasonably likely to materially affect, internal control over financial reporting

On April 3, 2006, the previously announced merger between Duke Energy and Cinergy was consummated Duke Energy is in process of integrating Cinergy's operations and has included Cinergy's activity in its evaluation of internal control over financial reporting pursuant to Section 404 of the Sarbanes-Oxley Act of 2002 See Notes 1, 2 and 3 to the Consolidated Financial Statements for additional information relating to the merger

Management's Annual Report On Internal Control Over Financial Reporting

Duke Energy's management is responsible for establishing and maintaining an adequate system of internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f) and 15d-15(f) Our internal control system was designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes, in accordance with generally accepted accounting principles Because of inherent limitations, internal control over financial reporting may not prevent or detect misstatements Also projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with policies and procedures may deteriorate

Duke Energy's management, including our Chief Executive Officer and Chief Financial Officer, has conducted an evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2006 based on the framework in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission Based on that evaluation, management concluded that our internal control over financial reporting was effective as of December 31, 2006

Deloitte & Touche LLP, our independent registered public accounting firm, has issued an attestation report on management's assessment of our internal control over financial reporting That report immediately follows

PART II

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of Duke Energy Corporation

We have audited management's assessment, included in the accompanying Management's Annual Report on Internal Control Over Financial Reporting, that Duke Energy Corporation and subsidiaries (the "Company") maintained effective internal control over financial reporting as of December 31, 2006, based on criteria established in *Internal Control--Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management's assessment that the Company maintained effective internal control over financial reporting as of December 31, 2006, is fairly stated, in all material respects, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and financial statement schedule as of and for the year ended December 31, 2006 of the Company and our report dated March 1, 2007 expressed an unqualified opinion on those financial statements and financial statement schedule and included explanatory paragraphs regarding the Company's adoption of a new accounting standard and the January 2, 2007 spin-off of the Company's natural gas businesses.

/s/ DELOITTE & TOUCHE LLP

Charlotte, North Carolina
March 1, 2007

PART III

Item 10. Directors, Executive Officers and Corporate Governance.

Reference to "Executive Officers of Duke Energy" is included in "Item 1 Business" of this report Information in response to this item is incorporated by reference to Duke Energy's Proxy Statement relating to Duke Energy's 2007 annual meeting of shareholders

Item 11. Executive Compensation.

Information in response to this item is incorporated by reference to Duke Energy's Proxy Statement relating to Duke Energy's 2007 annual meeting of shareholders

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.

Information in response to this item is incorporated by reference to Duke Energy's Proxy Statement relating to Duke Energy's 2007 annual meeting of shareholders

This table shows information about securities to be issued upon exercise of outstanding options, warrants and rights under Duke Energy's equity compensation plans, along with the weighted-average exercise price of the outstanding options, warrants and rights and the number of securities remaining available for future issuance under the plans

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights[1] (a)	Weighted-average exercise price of outstanding options, warrants and rights[1] (b)	Number of securities remaining available under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders	19,427,112[2]	$ 30.29	59,978,000[3]
Equity compensation plans not approved by security holders	1,877,646[4]	29 14	None
Total	21,304,758	$ 30.19	59,978,000

1 Duke Energy has not granted any warrants or rights under any equity compensation plans Amounts do not include 5,409,873 outstanding options with a weighted average exercise price of $24 27 assumed in connection with various mergers and acquisitions

2 Does not include 6,222,165 shares of Duke Energy Common Stock to be issued upon vesting of phantom stock and performance share awards outstanding as of December 31, 2006

3 Includes 14,978,000 shares remaining available for issuance for awards of restricted stock, performance shares or phantom stock under the Duke Energy Corporation 2006 Long-Term Incentive Plan

4 Does not include 516,435 shares of Duke Energy Common Stock to be issued upon vesting of phantom stock and performance share awards outstanding as of December 31, 2006

Item 13. Certain Relationships and Related Transactions, and Director Independence

Information in response to this item is incorporated by reference to Duke Energy's Proxy Statement relating to Duke Energy's 2007 annual meeting of shareholders

Item 14. Principal Accounting Fees and Services.

Information in response to this item is incorporated by reference to Duke Energy's Proxy Statement relating to Duke Energy's 2007 annual meeting of shareholders

[Table of Contents](#)

PART IV

Item 15. Exhibits, Financial Statement Schedules.

(a) Consolidated Financial Statements, Supplemental Financial Data and Supplemental Schedules included in Part II of this annual report are as follows:

Duke Energy Corporation:

Consolidated Financial Statements

Consolidated Statements of Operations for the Years Ended December 31, 2006, 2005 and 2004

Consolidated Balance Sheets as of December 31, 2006 and 2005

Consolidated Statements of Cash Flows for the Years Ended December 31, 2006, 2005 and 2004

~~Consolidated Statements of Common Stockholders' Equity and Comprehensive Income for the Years ended December 31, 2006, 2005 and 2004~~

Notes to the Consolidated Financial Statements

Quarterly Financial Data, as revised (unaudited, included in Note 26 to the Consolidated Financial Statements)

Consolidated Financial Statement Schedule II—Valuation and Qualifying Accounts and Reserves for the Years Ended December 31, 2006, 2005 and 2004

Report of Independent Registered Public Accounting Firm

Seperate Financial Statements of Subsidiaries not Consolidated Pursuant to Rule 3-09 of Regulation S-X:

TEPPCO Partners, L.P.:

Report of Independent Registered Public Accounting Firm

Consolidated Balance Sheets as of December 31, 2005 and 2004

Consolidated Statements of Income for the Years Ended December 31, 2005, 2004 and 2003

Consolidated Statements of Cash Flows for the Years Ended December 31, 2005, 2004 and 2003

Consolidated Statements of Partners' Capital for the Years Ended December 31, 2005, 2004 and 2003

Consolidated Statements of Comprehensive Income for the Years Ended December 31, 2005, 2004 and 2003

Notes to Consolidated Financial Statements

All other schedules are omitted because they are not required, or because the required information is included in the Consolidated Financial Statements or Notes

The consolidated financial statements of DCP Midstream, LLC (formerly Duke Energy Field Services, LLC), Duke Energy's 50/50 joint venture with ConocoPhillips, required to be included in this report pursuant to Rule 3-09 of Regulation S-X are to be filed by amendment no later than March 31, 2007

(c) Exhibits—See Exhibit Index immediately following the signature page.

Table of Contents

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

Date: March 1, 2007

DUKE ENERGY CORPORATION
(Registrant)

By: /s/ JAMES E. ROGERS

James E. Rogers
Chairman, President and
Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the date indicated.

(i) James E. Rogers*
Chairman, President and Chief Executive Officer (Principal Executive Officer and Director)

(ii) /s/ David L. Hauser
Group Executive and Chief Financial Officer (Principal Financial Officer)

(iii) Steven K. Young*
Senior Vice President and Controller (Principal Accounting Officer)

(iv) William Barnet, III*
Director

G. Alex Bernhardt, Sr.*
Director

Michael G. Browning*
Director

Phillip R. Cox*
Director

Ann Maynard Gray*
Director

James H. Hance, Jr.*
Director

James T. Rhodes*
Director

Mary L. Schapiro*
Director

Dudley S. Taft*
Director

Date: March 1, 2007

David L. Hauser, by signing his name hereto, does hereby sign this document on behalf of the registrant and on behalf of each of the above-named persons previously indicated by asterisk pursuant to a power of attorney duly executed by the registrant and such persons, filed with the Securities and Exchange Commission as an exhibit hereto.

By: /s/ DAVID L. HAUSER

Attorney-In-Fact

Table of Contents

CONSOLIDATED FINANCIAL STATEMENTS OF
TEPPCO PARTNERS, L.P.
INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Partners of TEPPCO Partners, L P :

We have audited the accompanying consolidated balance sheets of TEPPCO Partners, L P and subsidiaries as of December 31, 2005 and 2004, and the related consolidated statements of income, partners' capital and comprehensive income, and cash flows for each of the years in the three-year period ended December 31, 2005 These consolidated financial statements are the responsibility of the Partnership's management Our responsibility is to express an opinion on these consolidated financial statements based on our audits

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States) Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation We believe that our audits provide a reasonable basis for our opinion

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of TEPPCO Partners, L P and subsidiaries as of December 31, 2005 and 2004, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2005, in conformity with U S generally accepted accounting principles

As discussed in Note 20 to the consolidated financial statements, the Partnership has restated its consolidated balance sheet as of December 31, 2004, and the related consolidated statements of income, partners' capital and comprehensive income, and cash flows for the years ended December 31, 2004 and 2003

KPMG LLP

Houston, Texas

February 28, 2006, except for the effects of discontinued operations,

as discussed in Note 5, which is as of June 1, 2006

TEPPCO PARTNERS, L.P.
Consolidated Balance Sheets
(in thousands)

	December 31, 2005	December 31, 2004 (as restated)
ASSETS		
Current assets:		
Cash and cash equivalents	$ 119	$ 16,422
Accounts receivable, trade (net of allowance for doubtful accounts of $250 and $112)	803,373	553,628
Accounts receivable, related parties	5,207	11,845
Inventories	29,069	19,521
Other	61,361	42,138
Total current assets	899,129	643,554
Property, plant and equipment, at cost (net of accumulated depreciation and amortization of $474,332 and $407,670)	1,960,068	1,703,702
Equity investments	359,656	363,307
Intangible assets	376,908	407,358
Goodwill	16,944	16,944
Other assets	67,833	51,419
Total assets	$ 3,680,538	$ 3,186,284
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Accounts payable and accrued liabilities	$ 800,033	$ 564,464
Accounts payable, related parties	11,836	24,654
Accrued interest	32,840	32,292
Other accrued taxes	16,532	13,309
Other	75,970	46,593
Total current liabilities	937,211	681,312
Senior Notes	1,119,121	1,127,226
Other long-term debt	405,900	353,000
Other liabilities and deferred credits	16,936	13,643
Commitments and contingencies		
Partners' capital:		
Accumulated other comprehensive income	11	—
General partner's interest	(61,487)	(35,881)
Limited partners' interests	1,262,846	1,046,984
Total partners' capital	1,201,370	1,011,103
Total liabilities and partners' capital	$ 3,680,538	$ 3,186,284

See accompanying Notes to Consolidated Financial Statements.

TEPPCO PARTNERS, L.P.

Consolidated Statements of Income
(in thousands, except per Unit amounts)

	Years Ended December 31,		
	2005	2004	2003
		(as restated)	(as restated)
Operating revenues:			
Sales of petroleum products	$ 8,061,808	$ 5,426,832	$ 3,766,651
Transportation—Refined products	144,552	148,166	138,926
Transportation—LPGs	96,297	87,050	91,787
Transportation—Crude oil	37,614	37,177	29,057
Transportation—NGLs	43,915	41,204	39,837
Gathering—Natural gas	152,797	140,122	135,144
Other	68,051	67,539	54,430
Total operating revenues	8,605,034	5,948,090	4,255,832
Costs and expenses:			
Purchases of petroleum products	7,986,438	5,367,027	3,711,207
Operating, general and administrative	218,920	219,909	198,478
Operating fuel and power	48,972	48,139	41,362
Depreciation and amortization	110,729	112,284	100,728
Taxes—other than income taxes	20,610	17,340	15,597
Gains on sales of assets	(668)	(1,053)	(3,948)
Total costs and expenses	8,385,001	5,763,646	4,063,424
Operating income	220,033	184,444	192,408
Interest expense—net	(81,861)	(72,053)	(84,250)
Equity earnings	20,094	22,148	12,874
Other income—net	1,135	1,320	748
Income from continuing operations	159,401	135,859	121,780
Discontinued operations	3,150	2,689	—
Net income	$ 162,551	$ 138,548	$ 121,780
Net Income Allocation:			
Limited Partner Unitholders income from continuing operations	$ 112,744	$ 96,667	$ 86,357
Limited Partner Unitholders income from discontinued operations	2,228	1,913	—
Total Limited Partner Unitholders net income allocation	114,972	98,580	86,357
Class B Unitholder net income allocation	—	—	1,754
General Partner income from continuing operations	46,657	39,192	33,669
General Partner income from discontinued operations	922	776	—
Total General Partner net income allocation	47,579	39,968	33,669
Total net income allocated	$ 162,551	$ 138,548	$ 121,780
Basic and diluted net income per Limited Partner and Class B Unit:			
Continuing operations	$ 1.67	$ 1.53	$ 1.47
Discontinued operations	0.04	0.03	—
Basic and diluted net income per Limited Partner and Class B Unit	$ 1.71	$ 1.56	$ 1.47
Weighted average Limited Partner and Class B Units outstanding	67,397	62,999	59,765

See accompanying Notes to Consolidated Financial Statements.

TEPPCO PARTNERS, L.P.

Consolidated Statements of Cash Flows
(in thousands)

	Years Ended December 31, 2005	2004 (as restated)	2003 (as restated)
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 162,551	$ 138,548	$ 121,780
Adjustments to reconcile net income to cash provided by continuing operating activities:			
Income from discontinued operations	(3,150)	(2,689)	—
Depreciation and amortization	110,729	112,284	100,728
Earnings in equity investments, net of distributions	16,991	25,065	15,129
Gains on sales of assets	(668)	(1,053)	(3,948)
Non-cash portion of interest expense	1,624	(391)	4,793
Increase in accounts receivable	(249,745)	(181,690)	(100,085)
Decrease (increase) in accounts receivable, related parties	6,638	(14,693)	8,788
Increase in inventories	(970)	(3,433)	(956)
Increase in other current assets	(19,088)	(9,926)	(953)
Increase in accounts payable and accrued expenses	254,251	186,942	95,540
Increase (decrease) in accounts payable, related parties	(12,817)	4,360	7,381
Other	(15,623)	10,572	(5,773)
Net cash provided by continuing operating activities	250,723	263,896	242,424
Net cash provided by discontinued operations	3,782	3,271	—
Net cash provided by operating activities	254,505	267,167	242,424
CASH FLOWS FROM CONTINUING INVESTING ACTIVITIES:			
Proceeds from sales of assets	510	1,226	8,531
Proceeds from cash investments	—	—	750
Purchase of assets	(112,231)	(3,421)	(27,469)
Investment in Mont Belvieu Storage Partners, L.P.	(4,233)	(21,358)	(2,533)
Investment in Centennial Pipeline LLC	—	(1,500)	(4,000)
Purchase of additional interest in Centennial Pipeline LLC	—	—	(20,000)
Cash paid for linefill on assets owned	(14,408)	(957)	(3,070)
Capital expenditures	(220,553)	(156,749)	(126,707)
Net cash used in continuing investing activities	(350,915)	(182,759)	(174,498)
Net cash used in discontinued investing activities	—	(7,398)	(13,810)
Net cash used in investing activities	(350,915)	(190,157)	(188,308)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from revolving credit facility	657,757	324,200	382,000
Issuance of Limited Partner Units, net	278,806	—	287,506
Issuance of Senior Notes	—	—	198,570
Repayments on revolving credit facility	(604,857)	(181,200)	(604,000)
Repurchase and retirement of Class B Units	—	—	(113,814)
Debt issuance costs	(498)	—	(3,381)
General Partner's contributions	—	—	2
Distributions paid	(251,101)	(233,057)	(202,498)
Net cash provided by (used in) financing activities	80,107	(90,057)	(55,615)
Net decrease in cash and cash equivalents	(16,303)	(13,047)	(1,499)
Cash and cash equivalents at beginning of period	16,422	29,469	30,968
Cash and cash equivalents at end of period	$ 119	$ 16,422	$ 29,469
Non-cash investing activities:			
Net assets transferred to Mont Belvieu Storage Partners, L.P.	$ 1,429	$ —	$ 61,042
Supplemental disclosure of cash flows:			
Cash paid for interest (net of amounts capitalized)	$ 82,315	$ 77,510	$ 79,930

See accompanying Notes to Consolidated Financial Statements

TEPPCO PARTNERS, L.P.

Consolidated Statements of Partners' Capital
(in thousands, except Unit amounts)

	Outstanding Limited Partner Units	General Partner's Interest	Limited Partners' Interests	Accumulated Other Comprehensive (Loss) Income	Total
Partners' capital at December 31, 2002 (as restated)	**53,809,597**	**$ 12,104**	**$ 897,400**	**$ (20,055)**	**$ 889,449**
Issuance of Limited Partner Units, net	9,101,650	—	285,461	—	285,461
Retirement of Class B units	—	—	(11,175)	—	(11,175)
Net income on cash flow hedge	—	—	—	16,164	16,164
Reclassification due to discontinued portion of cash flow hedge	—	—	—	989	989
2003 net income allocation	—	33,669	86,357	—	120,026
2003 cash distributions	—	(54,725)	(145,427)	—	(200,152)
Issuance of Limited Partner Units upon exercise of options	87,307	2	2,045	—	2,047
Partners' capital at December 31, 2003 (as restated)	**62,998,554**	**(8,950)**	**1,114,661**	**(2,902)**	**1,102,809**
Adjustments to issuance of Limited Partner Units, net	—	—	(99)	—	(99)
Net income on cash flow hedge	—	—	—	2,902	2,902
2004 net income allocation	—	39,968	98,580	—	138,548
2004 cash distributions	—	(66,899)	(166,158)	—	(233,057)
Partners' capital at December 31, 2004 (as restated)	**62,998,554**	**(35,881)**	**1,046,984**	**—**	**1,011,103**
Issuance of Limited Partner Units, net	6,965,000	—	278,806	—	278,806
Changes in fair values of crude oil hedges	—	—	—	11	11
2005 net income allocation	—	47,579	114,972	—	162,551
2005 cash distributions	—	(73,185)	(177,916)	—	(251,101)
Partners' capital at December 31, 2005	**69,963,554**	**$ (61,487)**	**$ 1,262,846**	**$ 11**	**$ 1,201,370**

See accompanying Notes to Consolidated Financial Statements

TEPPCO PARTNERS, L.P.

Consolidated Statements of Comprehensive Income
(in thousands)

	Years Ended December 31,		
	2005	2004	2003
		(as restated)	(as restated)
Net income	$ 162,551	$ 138,548	$ 121,780
Net income on cash flow hedges	11	—	16,164
Comprehensive income	$ 162,562	$ 138,548	$ 137,944

See accompanying Notes to Consolidated Financial Statements

Table of Contents

TEPPCO PARTNERS, L P

Notes To Consolidated Financial Statements

Note 1. Partnership Organization

TEPPCO Partners, L P (the "Partnership"), a Delaware limited partnership, is a master limited partnership formed in March 1990 We operate through TE Products Pipeline Company, Limited Partnership ("TE Products"), TCTM, L P ("TCTM") and TEPPCO Midstream Companies, L P ("TEPPCO Midstream") Collectively, TE Products, TCTM and TEPPCO Midstream are referred to as the "Operating Partnerships " Texas Eastern Products Pipeline Company, LLC (the "Company" or "General Partner"), a Delaware limited liability company, serves as our general partner and owns a 2% general partner interest in us

On July 26, 2001, the Company restructured its general partner ownership of the Operating Partnerships to cause them to be indirectly wholly owned by us TEPPCO GP, Inc ("TEPPCO GP"), our subsidiary, succeeded the Company as general partner of the Operating Partnerships All remaining partner interests in the Operating Partnerships not already owned by us were transferred to us In exchange for this contribution, the Company's interest as our general partner was increased to 2% The increased percentage is the economic equivalent of the aggregate interest that the Company had prior to the restructuring through its combined interests in us and the Operating Partnerships As a result, we hold a 99 999% limited partner interest in the Operating Partnerships and TEPPCO GP holds a 0 001% general partner interest This reorganization was undertaken to simplify required financial reporting by the Operating Partnerships when the Operating Partnerships issue guarantees of our debt

Through February 23, 2005, the General Partner was an indirect wholly owned subsidiary of Duke Energy Field Services, LLC ("DEFS"), a joint venture between Duke Energy ~~Corporation ("Duke Energy") and ConocoPhillips. Duke Energy held an interest of approximately 70% in DEFS, and ConocoPhillips held the remaining interest of approximately 30%. On~~ February 24, 2005, the General Partner was acquired by DFI GP Holdings L P (formerly Enterprise GP Holdings L P) ("DFI"), an affiliate of EPCO, Inc ("EPCO"), a privately held company controlled by Dan L Duncan, for approximately $1 1 billion As a result of the transaction, DFI owns and controls the 2% general partner interest in us and has the right to receive the incentive distribution rights associated with the general partner interest In conjunction with an amended and restated administrative services agreement, EPCO performs all management, administrative and operating functions required for us, and we reimburse EPCO for all direct and indirect expenses that have been incurred in managing us As a result of the sale of our General Partner, DEFS and Duke Energy continued to provide some administrative services for us for a period of up to one year after the sale, at which time, we assumed these services In connection with us assuming the operations of certain of the TEPPCO Midstream assets from DEFS, certain DEFS employees became employees of EPCO effective June 1, 2005

At formation in 1990, we completed an initial public offering of 26,500,000 units representing Limited Partner Interests ("Limited Partner Units") at $10 00 per Limited Partner Unit In connection with our formation, the Company received 2,500,000 Deferred Participation Interests ("DPIs") Effective April 1, 1994, the DPIs were converted to Limited Partner Units, but they have not been listed for trading on the New York Stock Exchange These Limited Partner Units were assigned to Duke Energy when ownership of the Company was transferred from Duke Energy to DEFS in 2000 On February 24, 2005, DFI entered into an LP Unit Purchase and Sale Agreement with Duke Energy and purchased these 2,500,000 Limited Partner Units for $104 0 million As of December 31, 2005, none of these Limited Partner Units had been sold by DFI

At December 31, 2005, 2004 and 2003, we had outstanding 69,963,554, 62,998,554 and 62,998,554 Limited Partner Units, respectively At December 31, 2002, we had outstanding 3,916,547 Class B Limited Partner Units ("Class B Units"), which were issued to Duke Energy Transport and Trading Company, LLC ("DETTCO") in connection with an acquisition of assets initially acquired in 1998 On April 2, 2003, we repurchased and retired all of the 3,916,547 previously outstanding Class B Units with proceeds from the issuance of additional Limited Partner Units (see Note 11) Collectively, the Limited Partner Units and Class B Units are referred to as "Units"

As used in this Report, "we," "us," "our," the "Partnership" and "TEPPCO" mean TEPPCO Partners, L P and, where the context requires, include our subsidiaries

We restated our consolidated financial statements and related financial information for the years ended December 31, 2004 and 2003, for an accounting correction In addition, the restatement adjustment impacted quarterly periods with the fiscal years ended December 31, 2005, 2004 and 2003 See Note 20 for a discussion of the restatement adjustment and the impact on previously issued financial statements

Note 2. Summary of Significant Accounting Policies

We adhere to the following significant accounting policies in the preparation of our consolidated financial statements

Basis of Presentation and Principles of Consolidation. Throughout the consolidated financial statements and accompanying notes, all referenced amounts related to prior periods reflect the balances and amounts on a restated basis The financial statements include our accounts on a consolidated basis We have eliminated all significant intercompany items in consolidation We have reclassified

TEPPCO PARTNERS, L P
Notes To Consolidated Financial Statements—(Continued)

certain amounts from prior periods to conform to the current presentation Our results for the years ended December 31, 2005 and 2004 reflect the operations and activities of Jonah Gas Gathering Company's Pioneer plant as discontinued operations

Use of Estimates. The preparation of financial statements in conformity with generally accepted accounting principles in the United States requires our management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting periods Although we believe these estimates are reasonable, actual results could differ from those estimates

Business Segments. We operate and report in three business segments: transportation and storage of refined products, liquefied petroleum gases ("LPGs") and petrochemicals ("Downstream Segment"); gathering, transportation, marketing and storage of crude oil and distribution of lubrication oils and specialty chemicals ("Upstream Segment"); and gathering of natural gas, fractionation of natural gas liquids ("NGLs") and transportation of NGLs ("Midstream Segment") Our reportable segments offer different products and services and are managed separately because each requires different business strategies

Our interstate transportation operations, including rates charged to customers, are subject to regulations prescribed by the Federal Energy Regulatory Commission ("FERC") We refer to refined products, LPGs, petrochemicals, crude oil, NGLs and natural gas in this Report, collectively, as "petroleum products" or "products "

Revenue Recognition Our Downstream Segment revenues are earned from transportation and storage of refined products and LPGs, intrastate transportation of petrochemicals, sale of product inventory and other ancillary services. Transportation revenues are recognized as products are delivered to customers. Storage revenues are recognized upon receipt of products into storage and upon performance of storage services Terminaling revenues are recognized as products are out-loaded Revenues from the sale of product inventory are recognized when the products are sold

Our Upstream Segment revenues are earned from gathering, transportation, marketing and storage of crude oil, and distribution of lubrication oils and specialty chemicals principally in Oklahoma, Texas, New Mexico and the Rocky Mountain region Revenues are also generated from trade documentation and pumpover services, primarily at Cushing, Oklahoma, and Midland, Texas Revenues are accrued at the time title to the product sold transfers to the purchaser, which typically occurs upon receipt of the product by the purchaser, and purchases are accrued at the time title to the product purchased transfers to our crude oil marketing company, TEPPCO Crude Oil, L P ("TCO"), which typically occurs upon our receipt of the product Revenues related to trade documentation and pumpover fees are recognized as services are completed

Except for crude oil purchased from time to time as inventory, our policy is to purchase only crude oil for which we have a market to sell and to structure sales contracts so that crude oil price fluctuations do not materially affect the margin received As we purchase crude oil, we establish a margin by selling crude oil for physical delivery to third party users or by entering into a future delivery obligation Through these transactions, we seek to maintain a position that is balanced between crude oil purchases and sales and future delivery obligations However, certain basis risks (the risk that price relationships between delivery points, classes of products or delivery periods will change) cannot be completely hedged

Our Midstream Segment revenues are earned from the gathering of natural gas, transportation of NGLs and fractionation of NGLs Gathering revenues are recognized as natural gas is received from the customer Transportation revenues are recognized as NGLs are delivered to customers Revenues are also earned from the sale of condensate liquid extracted from the natural gas stream to an Upstream Segment marketing affiliate Fractionation revenues are recognized ratably over the contract year as products are delivered We generally do not take title to the natural gas gathered, NGLs transported or NGLs fractionated, with the exception of inventory imbalances discussed in "Natural Gas Imbalances " Therefore, the results of our Midstream Segment are not directly affected by changes in the prices of natural gas or NGLs

Cash and Cash Equivalents. Cash equivalents are defined as all highly marketable securities with maturities of three months or less when purchased The carrying value of cash and cash equivalents approximate fair value because of the short term nature of these investments

TEPPCO PARTNERS, L P

Notes To Consolidated Financial Statements—(Continued)

Allowance for Doubtful Accounts. We establish provisions for losses on accounts receivable if we determine that we will not collect all or part of the outstanding balance Collectibility is reviewed regularly and an allowance is established or adjusted, as necessary, using the specific identification method The following table presents the activity of our allowance for doubtful accounts for the years ended December 31, 2005, 2004 and 2003 (in thousands):

	Years Ended December 31,		
	2005	2004	2003
Balance at beginning of period	$ 112	$ 4,700	$ 4,608
Charges to expense	829	536	793
Deductions and other	(691)	(5,124)	(701)
Balance at end of period	$ 250	$ 112	$ 4,700

Inventories. Inventories consist primarily of petroleum products and crude oil, which are valued at the lower of cost (weighted average cost method) or market Our Downstream Segment acquires and disposes of various products under exchange agreements Receivables and payables arising from these transactions are usually satisfied with products rather than cash The net balances of exchange receivables and payables are valued at weighted average cost and included in inventories Inventories of materials and supplies, used for ongoing replacements and expansions, are carried at the lower of fair value or cost

Property, Plant and Equipment. We record property, plant and equipment at its acquisition cost Additions to property, plant and equipment, including major replacements or betterments, are recorded at cost We charge replacements and renewals of minor items of property that do not materially increase values or extend useful lives to maintenance expense Depreciation expense is computed on the straight-line method using rates based upon expected useful lives of various classes of assets (ranging from 2% to 20% per annum)

We evaluate impairment of long-lived assets in accordance with Statement of Financial Accounting Standards ("SFAS") No 144, Accounting for the Impairment or Disposal of Long-Lived Assets Long-lived assets are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable Recoverability of the carrying amount of assets to be held and used is measured by a comparison of the carrying amount of the asset to estimated future net cash flows expected to be generated by the asset If such assets are considered to be impaired, the impairment to be recognized is measured by the amount by which the carrying amount of the assets exceeds the estimated fair value of the assets Assets to be disposed of are reported at the lower of the carrying amount or estimated fair value less costs to sell

Asset Retirement Obligations. In June 2001, the Financial Accounting Standards Board ("FASB") issued SFAS No 143, Accounting for Asset Retirement Obligations SFAS 143 requires us to record the fair value of an asset retirement obligation as a liability in the period in which we incur a legal obligation for the retirement of tangible long-lived assets A corresponding asset is also recorded and depreciated over the life of the asset After the initial measurement of the asset retirement obligation, the liability will be adjusted at the end of each reporting period to reflect changes in the estimated future cash flows underlying the obligation Determination of any amounts recognized upon adoption is based upon numerous estimates and assumptions, including future retirement costs, future inflation rates and the credit-adjusted risk-free interest rates

The Downstream Segment assets consist primarily of an interstate trunk pipeline system and a series of storage facilities that originate along the upper Texas Gulf Coast and extend through the Midwest and northeastern United States We transport refined products, LPGs and petrochemicals through the pipeline system These products are primarily received in the south end of the system and stored and/or transported to various points along the system per customer nominations The Upstream Segment's operations include purchasing crude oil from producers at the wellhead and providing delivery, storage and other services to its customers The properties in the Upstream Segment consist of interstate trunk pipelines, pump stations, trucking facilities, storage tanks and various gathering systems primarily in Texas and Oklahoma The Midstream Segment gathers natural gas from wells owned by producers and delivers natural gas and NGLs on its pipeline systems, primarily in Texas, Wyoming, New Mexico and Colorado The Midstream Segment also owns and operates two NGL fractionator facilities in Colorado

We have completed our assessment of SFAS 143, and we have determined that we are obligated by contractual or regulatory requirements to remove certain facilities or perform other remediation upon retirement of our assets However, we are not able to reasonably determine the fair value of the asset retirement obligations for our trunk, interstate and gathering pipelines and our surface facilities, since future dismantlement and removal dates are indeterminate

In order to determine a removal date for our gathering lines and related surface assets, reserve information regarding the production life of the specific field is required As a transporter and gatherer of crude oil and natural gas, we are not a producer of the field reserves, and we therefore do not have access to adequate forecasts that predict the timing of expected production for existing reserves on those fields in which we gather crude oil and natural gas In the absence of such information, we are not able to make a reasonable

TEPPCO PARTNERS, L P

Notes To Consolidated Financial Statements—(Continued)

estimate of when future dismantlement and removal dates of our gathering assets will occur With regard to our trunk and interstate pipelines and their related surface assets, it is impossible to predict when demand for transportation of the related products will cease Our right-of-way agreements allow us to maintain the right-of-way rather than remove the pipe In addition, we can evaluate our trunk pipelines for alternative uses, which can be and have been found.

We will record such asset retirement obligations in the period in which more information becomes available for us to reasonably estimate the settlement dates of the retirement obligations The adoption of SFAS 143 did not have an effect on our financial position, results of operations or cash flows

Capitalization of Interest. We capitalize interest on borrowed funds related to capital projects only for periods that activities are in progress to bring these projects to their intended use The weighted average rate used to capitalize interest on borrowed funds was 5 73%, 5 74% and 6 50% for the years ended December 31, 2005, 2004 and 2003, respectively During the years ended December 31, 2005, 2004 and 2003, the amount of interest capitalized was $6 8 million, $4 2 million and $5 3 million, respectively

Intangible Assets. Intangible assets on the consolidated balance sheets consist primarily of gathering contracts assumed in the acquisition of Jonah Gas Gathering System ("Jonah") on September 30, 2001, and the acquisition of Val Verde Gathering System ("Val Verde") on June 30, 2002, a fractionation agreement and other intangible assets (see Note 3) Included in equity investments on the consolidated balance sheets are excess investments in Centennial Pipeline LLC ("Centennial") and Seaway Crude Pipeline Company ("Seaway")

In connection with the acquisitions of Jonah and Val Verde, we assumed contracts that dedicate future production from natural gas wells in the Green River Basin in Wyoming, and we assumed fixed-term contracts with customers that gather coal bed methane ("CBM") from the San Juan Basin in New Mexico and Colorado, respectively. The value assigned to these intangible assets relates to contracts with customers that are for either a fixed term or which dedicate total future lease production to the gathering system These intangible assets are amortized on a unit-of-production basis, based upon the actual throughput of the system over the expected total throughput for the lives of the contracts. Revisions to the unit-of-production estimates may occur as additional production information is made available to us (see Note 3)

In connection with the purchase of the fractionation facilities in 1998, we entered into a fractionation agreement with DEFS The fractionation agreement is being amortized on a straight-line basis over a period of 20 years, which is the term of the agreement with DEFS.

In connection with the acquisition of crude supply and transportation assets in November 2003, we acquired intangible customer contracts for $8 7 million, which are amortized on a unit-of-production basis (see Note 5)

In connection with the formation of Centennial, we recorded excess investment, the majority of which is amortized on a unit-of-production basis over a period of 10 years In connection with the acquisition of our interest in Seaway, we recorded excess investment, which is amortized on a straight-line basis over a period of 39 years (see Note 3).

Goodwill. Goodwill represents the excess of purchase price over fair value of net assets acquired and is presented on the consolidated balance sheets net of accumulated amortization We account for goodwill under SFAS No 142, Goodwill and Other Intangible Assets, which was issued by the FASB in July 2001 (see Note 3) SFAS 142 prohibits amortization of goodwill and intangible assets with indefinite useful lives, but instead requires testing for impairment at least annually SFAS 142 requires that intangible assets with definite useful lives be amortized over their respective estimated useful lives Beginning January 1, 2002, effective with the adoption of SFAS 142, we no longer record amortization expense related to goodwill.

Environmental Expenditures. We accrue for environmental costs that relate to existing conditions caused by past operations Environmental costs include initial site surveys and environmental studies of potentially contaminated sites, costs for remediation and restoration of sites determined to be contaminated and ongoing monitoring costs, as well as damages and other costs, when estimable We monitor the balance of accrued undiscounted environmental liabilities on a regular basis We record liabilities for environmental costs at a specific site when our liability for such costs is probable and a reasonable estimate of the associated costs can be made Adjustments to initial estimates are recorded, from time to time, to reflect changing circumstances and estimates based upon additional information developed in subsequent periods Estimates of our ultimate liabilities associated with environmental costs are particularly difficult to make with certainty due to the number of variables involved, including the early stage of investigation at certain sites, the lengthy time frames required to complete remediation alternatives available and the evolving nature of environmental laws and regulations

TEPPCO PARTNERS, L.P.

Notes To Consolidated Financial Statements—(Continued)

The following table presents the activity of our environmental reserve for the years ended December 31, 2005, 2004 and 2003 (in thousands):

	Years Ended December 31,		
	2005	2004	2003
Balance at beginning of period	$ 5,037	$ 7,639	$ 7,693
Charges to expense	2,530	5,178	6,824
Deductions and other	(5,120)	(7,780)	(6,878)
Balance at end of period	$ 2,447	$ 5,037	$ 7,639

Natural Gas Imbalances. Gas imbalances occur when gas producers (customers) deliver more or less actual natural gas gathering volumes to our gathering systems than they originally nominated. Actual deliveries are different from nominated volumes due to fluctuations in gas production at the wellhead. If the customers supply more natural gas gathering volumes than they nominated, Val Verde and Jonah record a payable for the amount due to customers and also record a receivable for the same amount due from connecting pipeline transporters or shippers. To the extent that these amounts are not cashed out monthly on Val Verde, if the customers supply less natural gas gathering volumes than they nominated, Val Verde and Jonah record a receivable reflecting the amount due from customers and a payable for the same amount due to connecting pipeline transporters or shippers. We record natural gas imbalances using a mark-to-market approach.

Income Taxes. We are a limited partnership. As such, we are not a taxable entity for federal and state income tax purposes and do not directly pay federal and state income tax. Our taxable income or loss, which may vary substantially from the net income or net loss we report in our consolidated statements of income, is includable in the federal and state income tax returns of each unitholder. Accordingly, no recognition has been given to federal and state income taxes for our operations. The aggregate difference in the basis of our net assets for financial and tax reporting purposes cannot be readily determined as we do not have access to information about each unitholders' tax attributes in the Partnership.

Use of Derivatives. We account for derivative financial instruments in accordance with SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, and SFAS No. 138, *Accounting for Certain Derivative Instruments and Certain Hedging Activities, an amendment of FASB Statement No. 133*. These statements establish accounting and reporting standards requiring that derivative instruments (including certain derivative instruments embedded in other contracts) be recorded on the balance sheet at fair value as either assets or liabilities. The accounting for changes in the fair value of a derivative instrument depends on the intended use of the derivative and the resulting designation, which is established at the inception of a derivative.

Our derivative instruments consist primarily of interest rate swaps and contracts for the purchase and sale of petroleum products in connection with our crude oil marketing activities. Substantially all derivative instruments related to our crude oil marketing activities meet the normal purchases and sales criteria of SFAS 133, as amended, and as such, changes in the fair value of petroleum product purchase and sales agreements are reported on the accrual basis of accounting. SFAS 133 describes normal purchases and sales as contracts that provide for the purchase or sale of something other than a financial instrument or derivative instrument that will be delivered in quantities expected to be used or sold by the reporting entity over a reasonable period in the normal course of business.

For all hedging relationships, we formally document at inception the hedging relationship and its risk-management objective and strategy for undertaking the hedge, the hedging instrument, the item, the nature of the risk being hedged, how the hedging instrument's effectiveness in offsetting the hedged risk will be assessed and a description of the method of measuring ineffectiveness. This process includes linking all derivatives that are designated as fair value or cash flow to specific assets and liabilities on the balance sheet or to specific firm commitments or forecasted transactions. We also formally assess, both at the hedge's inception and on an ongoing basis, whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in fair values or cash flows of hedged items. If it is determined that a derivative is not highly effective as a hedge or that it has ceased to be a highly effective hedge, we discontinue hedge accounting prospectively.

For derivative instruments designated as fair value hedges, gains and losses on the derivative instrument are offset against related results on the hedged item in the statement of income. Changes in the fair value of a derivative that is highly effective and that is designated and qualifies as a fair value hedge, along with the loss or gain on the hedged asset or liability or unrecognized firm commitment of the hedged item that is attributable to the hedged risk, are recorded in earnings. Changes in the fair value of a derivative that is highly effective and that is designated and qualifies as a cash flow hedge are recorded in other comprehensive income to the extent that the derivative is effective as a hedge, until earnings are affected by the variability in cash flows of the designated hedged item. Hedge effectiveness is measured at least quarterly based on the relative cumulative changes in fair value between the derivative contract and the hedged item over time The ineffective portion of the change in fair value of a derivative instrument that qualifies as either a fair value hedge or a cash flow hedge is reported immediately in earnings

According to SFAS 133, as amended, we are required to discontinue hedge accounting prospectively when it is determined that the derivative is no longer effective in offsetting changes in the fair value or cash flows of the hedged item, the derivative expires or is sold, terminated, or exercised, the derivative is de-designated as a hedging instrument, because it is unlikely that a forecasted transaction will occur, a hedged firm commitment no longer meets the definition of a firm commitment, or management determines that designation of the derivative as a hedging instrument is no longer appropriate

When hedge accounting is discontinued because it is determined that the derivative no longer qualifies as an effective fair value hedge, we continue to carry the derivative on the balance sheet at its fair value and no longer adjust the hedged asset or liability for changes in fair value The adjustment of the carrying amount of the hedged asset or liability is accounted for in the same manner as other components of the carrying amount of that asset or liability When hedge accounting is discontinued because the hedged item no longer meets the definition of a firm commitment, we continue to carry the derivative on the balance sheet at its fair value, remove any asset or liability that was recorded pursuant to recognition of the firm commitment from the balance sheet, and recognize any gain or loss in earnings When hedge accounting is discontinued because it is probable that a forecasted transaction will not occur, we continue to carry the derivative on the balance sheet at its fair value with subsequent changes in fair value included in earnings, and gains and losses that were accumulated in other comprehensive income are recognized immediately in earnings. In all other situations in which hedge accounting is discontinued, we continue to carry the derivative at its fair value on the balance sheet and recognize any subsequent changes in its fair value in earnings

Fair Value of Financial Instruments The carrying amount of cash and cash equivalents, accounts receivable, inventories, other current assets, accounts payable and accrued liabilities, other current liabilities and derivatives approximates their fair value due to their short-term nature The fair values of these financial instruments are represented in our consolidated balance sheets

Net Income Per Unit. Basic net income per Unit is computed by dividing net income, after deduction of the General Partner's interest, by the weighted average number of Units outstanding (a total of 67 4 million Units, 63 0 million Units and 59 8 million Units for the years ended December 31, 2005, 2004 and 2003, respectively). The General Partner's percentage interest in our net income is based on its percentage of cash distributions from Available Cash for each year (see Note 11) The General Partner was allocated $47 6 million (representing 29 27%) of net income for the year ended December 31, 2005, $40 0 million (representing 28 85%) of net income for the year ended December 31, 2004, and $33 7 million (representing 27.65%) of net income for the year ended December 31, 2003 The General Partner's percentage interest in our net income increases as cash distributions paid per Unit increase, in accordance with our limited partnership agreement.

Diluted net income per Unit is similar to the computation of basic net income per Unit discussed above, except that the denominator is increased to include the dilutive effect of outstanding Unit options by application of the treasury stock method For the year ended December 31, 2003, the denominator was increased by 11,878 Units For the years ended December 31, 2005 and 2004, diluted net income per Unit equaled basic net income per Unit as all remaining outstanding Unit options were exercised during the third quarter of 2003 (see Note 13)

Unit Option Plan. We have not granted options for any periods presented For options outstanding under the 1994 Long Term Incentive Plan (see Note 13), we followed the intrinsic value method of accounting for recognizing stock-based compensation expense Under this method, we record no compensation expense for Unit options granted when the exercise price of the options granted is equal to, or greater than, the market price of our Units on the date of the grant During the year ended December 31, 2003, all remaining outstanding Unit options were exercised

In December 2002, SFAS No 148, *Accounting for Stock-Based Compensation – Transition and Disclosure* was issued SFAS 148 amends SFAS No 123, *Accounting for Stock-Based Compensation*, and provides alternative methods of transition for a voluntary change to the fair value based method of accounting for stock-based employee compensation In addition, SFAS 148 amends the disclosure requirements of SFAS 123 to require prominent disclosure in both annual and interim financial statements about the method of accounting for stock-based employee compensation and the effect of the method used on reported results Certain of the disclosure modifications are required for fiscal years ending after December 15, 2002, and are included in Note 13

Assuming we had used the fair value method of accounting for our Unit option plan, pro forma net income would equal reported net income for the years ended December 31, 2005, 2004 and 2003 Pro forma net income per Unit would equal reported net income per Unit for the periods presented The adoption of SFAS 148 did not have an effect on our financial position, results of operations or cash flows

TEPPCO PARTNERS, L P
Notes To Consolidated Financial Statements—(Continued)

New Accounting Pronouncements In December 2004, the FASB issued SFAS No 123(R), *Share-Based Payment* SFAS 123(R) requires compensation costs related to share-based payment transactions to be recognized in the financial statements With limited exceptions, the amount of the compensation cost is to be measured based on the grant-date fair value of the equity or liability instruments issued In addition, liability awards are to be re-measured each reporting period Compensation cost will be recognized over the period that an employee provides service in exchange for the award SFAS 123(R) is a revision of SFAS No 123, *Accounting for Stock-Based Compensation*, as amended by SFAS No 148,*Accounting for Stock-Based Compensation – Transition and Disclosure* and supersedes Accounting Principles Board ("APB") Opinion No 25, *Accounting for Stock Issued to Employees* SFAS 123(R) is effective for public companies as of the first interim or annual reporting period of the first fiscal year beginning after June 15, 2005 The Securities and Exchange Commission amended the implementation date of SFAS 123(R) to begin with the first interim or annual reporting period of the company's first fiscal year beginning on or after June 15, 1005 As such, we will adopt SFAS 123(R) in the first quarter of 2006 Companies are permitted to adopt SFAS 123(R) prior to the extended date All public companies that adopted the fair-value-based method of accounting must use the modified prospective transition method and may elect to use the modified retrospective transition method We do not believe that the adoption of SFAS 123(R) will have a material effect on our financial position, results of operations or cash flows

In November 2004, the Emerging Issues Task Force ("EITF") reached consensus in EITF 03-13, *Applying the Conditions in Paragraph 42 of FASB Statement No. 144, Accounting for Impairment or Disposal of Long-Lived Assets, in Determining Whether to Report* Discontinued Operations, to clarify whether a component of an enterprise that is either disposed of or classified as held for sale qualifies for income statement presentation as discontinued operations The FASB ratified the consensus on November 30, 2004 The consensus is to be applied prospectively with regard to a component of an enterprise that is either disposed of or classified as held for sale in reporting periods beginning after December 15, 2004 The consensus may be applied retrospectively for previously reported operating results related to disposal transactions initiated within an enterprise's reporting period that included the date that this consensus was ratified The adoption of EITF 03-13 did not have an effect on our financial position, results of operations or cash flows

In March 2005, the FASB issued FASB Interpretation No 47, *Accounting for Conditional Asset Retirement Obligations, an interpretation of FASB Statement No. 143* ("FIN 47") FIN 47 clarifies that the term, conditional asset retirement obligation as used in SFAS No 143, *Accounting for Asset Retirement Obligations*, refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional upon a future event that may or may not be within the control of the entity Even though uncertainty about the timing and/or method of settlement exists and may be conditional upon a future event, the obligation to perform the asset retirement activity is unconditional Accordingly, an entity is required to recognize a liability for the fair value of a conditional asset retirement obligation if the fair value of the liability can be reasonably estimated Uncertainty about the timing and/or method of settlement of a conditional asset retirement obligation should be factored into the measurement of the liability when sufficient information exists The fair value of a liability for the conditional asset retirement obligation should be recognized when incurred generally upon acquisition, construction, or development or through the normal operation of the asset SFAS 143 acknowledges that in some cases, sufficient information may not be available to reasonably estimate the fair value of an asset retirement obligation FIN 47 also clarifies when an entity would have sufficient information to reasonably estimate the fair value of an asset retirement obligation FIN 47 is effective no later than the end of reporting periods ending after December 15, 2005, and early adoption of FIN 47 is encouraged We adopted FIN 47 in the fourth quarter of 2005 The adoption of FIN 47 did not have a material effect on our financial position, results of operations or cash flows

In June 2005, the EITF reached consensus in EITF 04-5, *Determining Whether a General Partner, or the General Partners as a Group, Controls a Limited Partnership or Similar Entity When the Limited Partners Have Certain Rights*, to provide guidance on how general partners in a limited partnership should determine whether they control a limited partnership and therefore should consolidate it. The EITF agreed that the presumption of general partner control would be overcome only when the limited partners have either of two types of rights The first type, referred to as kick-out rights, is the right to dissolve or liquidate the partnership or otherwise remove the general partner without cause The second type, referred to as participating rights, is the right to effectively participate in significant decisions made in the ordinary course of the partnership's business The kick-out rights and the participating rights must be substantive in order to overcome the presumption of general partner control The consensus is effective for general partners of all new limited partnerships formed and for existing limited partnerships for which the partnership agreements are modified subsequent to the date of FASB ratification (June 29, 2005) For existing limited partnerships that have not been modified, the guidance in EITF 04-5 is effective no later than the beginning of the first reporting period in fiscal years beginning after December 15, 2005 We do not believe that the adoption of EITF 04-5 will have a material effect on our financial position, results of operations or cash flows

In December 2004, the FASB issued SFAS No 153, *Exchanges of Nonmonetary Assets, an amendment of APB Opinion 29* SFAS 153 amends APB Opinion No 29, Accounting for Nonmonetary Exchanges, to eliminate the exception for nonmonetary exchanges of

TEPPCO PARTNERS, L.P.

Notes To Consolidated Financial Statements—(Continued)

similar productive assets and replaces it with a general exception for exchanges of nonmonetary assets that do not have commercial substance. A nonmonetary exchange has commercial substance if the future cash flows of the entity are expected to change significantly as a result of the exchange. SFAS 153 is effective for nonmonetary asset exchanges occurring in fiscal periods beginning after June 15, 2005. We adopted SFAS 153 during the second quarter of 2005. The adoption of SFAS 153 did not have a material effect on our financial position, results of operations or cash flows.

In May 2005, the FASB issued SFAS No. 154, *Accounting Changes and Error Corrections*. SFAS 154 establishes new standards on accounting for changes in accounting principles. All such changes must be accounted for by retrospective application to the financial statements of prior periods unless it is impracticable to do so. SFAS 154 completely replaces APB Opinion No. 20, *Accounting Changes*, and SFAS No. 3, *Reporting Accounting Changes in Interim Periods*. However, it carries forward the guidance in those pronouncements with respect to accounting for changes in estimates, changes in the reporting entity, and the correction of errors. SFAS 154 is effective for accounting changes and error corrections made in fiscal years beginning after December 15, 2005, with early adoption permitted for changes and corrections made in years beginning after June 1, 2005. The application of SFAS 154 does not affect the transition provisions of any existing pronouncements, including those that are in the transition phase as of the effective date of SFAS 154. We do not believe that the adoption of SFAS 154 will have a material effect on our financial position, results of operations or cash flows.

In September 2005, the EITF reached consensus in EITF 04-13, *Accounting for Purchases and Sales of Inventory with the Same Counterparty*, to define when a purchase and a sale of inventory with the same party that operates in the same line of business should be considered a single nonmonetary transaction subject to APB Opinion No. 29, *Accounting for Nonmonetary Transactions*. Two or more inventory transactions with the same party should be combined if they are entered into in contemplation of one another. The EITF also requires entities to account for exchanges of inventory in the same line of business at fair value or recorded amounts based on inventory classification. The guidance in EITF 04-13 is effective for new inventory arrangements entered into in reporting periods beginning after March 15, 2006. We are currently evaluating what impact EITF 04-13 will have on our financial statements, but at this time we do not believe that the adoption of EITF 04-13 will have a material effect on our financial position, results of operations or cash flows.

Note 3. Goodwill and Other Intangible Assets

Goodwill. Goodwill represents the excess of purchase price over fair value of net assets acquired and is presented on the consolidated balance sheets net of accumulated amortization. We account for goodwill under SFAS No. 142, *Goodwill and Other Intangible Assets*, which was issued by the FASB in July 2001. SFAS 142 prohibits amortization of goodwill and intangible assets with indefinite useful lives, but instead requires testing for impairment at least annually. We test goodwill and intangible assets for impairment annually at December 31.

To perform an impairment test of goodwill, we have identified our reporting units and have determined the carrying value of each reporting unit by assigning the assets and liabilities, including the existing goodwill and intangible assets, to those reporting units. We then determine the fair value of each reporting unit and compare it to the carrying value of the reporting unit. We will continue to compare the fair value of each reporting unit to its carrying value on an annual basis to determine if an impairment loss has occurred. There have been no goodwill impairment losses recorded since the adoption of SFAS 142.

The following table presents the carrying amount of goodwill at December 31, 2005 and 2004, by business segment (in thousands):

	Downstream Segment	Midstream Segment	Upstream Segment	Segments Total
Goodwill	$ —	$ 2,777	$ 14,167	$ 16,944

TEPPCO PARTNERS, L P

Notes To Consolidated Financial Statements—(Continued)

Other Intangible Assets The following table reflects the components of intangible assets, including excess investments, being amortized at December 31, 2005 and 2004 (in thousands):

	December 31, 2005		December 31, 2004	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Intangible assets:				
Gathering and transportation agreements	$ 464,337	$ (118,921)	$ 464,337	$ (91,262)
Fractionation agreement	38,000	(14,725)	38,000	(12,825)
Other	10,226	(2,009)	12,262	(3,154)
Subtotal	$ 512,563	$ (135,655)	$ 514,599	$ (107,241)
Excess investments:				
Centennial Pipeline LLC	$ 33,400	$ (12,947)	$ 33,400	$ (8,875)
Seaway Crude Pipeline Company	27,100	(3,764)	27,100	(3,072)
Subtotal	$ 60,500	$ (16,711)	$ 60,500	$ (11,947)
Total intangible assets	$ 573,063	$ (152,366)	$ 575,099	$ (119,188)

SFAS 142 requires that intangible assets with finite useful lives be amortized over their respective estimated useful lives If an intangible asset has a finite useful life, but the precise length of that life is not known, that intangible asset shall be amortized over the best estimate of its useful life At a minimum, we will assess the useful lives and residual values of all intangible assets on an annual basis to determine if adjustments are required Amortization expense on intangible assets was $30 5 million, $32 2 million and $36 2 million for the years ended December 31, 2005, 2004 and 2003, respectively Amortization expense on excess investments included in equity earnings was $4 8 million, $3 8 million and $4 0 million for the years ended December 31, 2005, 2004 and 2003, respectively

The values assigned to our intangible assets for natural gas gathering contracts on the Jonah and the Val Verde systems are amortized on a unit-of-production basis, based upon the actual throughput of the systems compared to the expected total throughput for the lives of the contracts On a quarterly basis, we may obtain limited production forecasts and updated throughput estimates from some of the producers on the systems, and as a result, we evaluate the remaining expected useful lives of the contract assets based on the best available information During the fourth quarter of 2004 and the first and second quarters of 2005, certain limited production forecasts were obtained from some of the producers on the Jonah system related to future expansions of the system, and as a result, we increased our best estimate of future throughput on the system, which resulted in extensions in the remaining lives of the intangible assets During the fourth quarter of 2004 and the third quarter of 2005, certain limited coal bed methane production forecasts were obtained from some of the producers on the Val Verde system whose contracts are included in the intangible assets These forecasts indicated lower coal bed methane production estimates over the contract periods, and as a result, we decreased our best estimate of future throughput on the Val Verde system, which resulted in increases to amortization expense on the intangible assets Further revisions to these estimates may occur as additional production information is made available to us

The values assigned to our fractionation agreement and other intangible assets are generally amortized on a straight-line basis Our fractionation agreement is being amortized over its contract period of 20 years The amortization periods for our other intangible assets, which include non-compete and other agreements, range from 3 years to 15 years The value of $8 7 million assigned to our crude supply and transportation intangible customer contracts is being amortized on a unit-of-production basis (see Note 5)

The value assigned to our excess investment in Centennial was created upon its formation Approximately $30 0 million is related to a contract and is being amortized on a unit-of-production basis based upon the volumes transported under the contract compared to the guaranteed total throughput of the contract over a 10-year life The remaining $3 4 million is related to a pipeline and is being amortized on a straight-line basis over the life of the pipeline, which is 35 years The value assigned to our excess investment in Seaway was created upon acquisition of our 50% ownership interest in 2000 We are amortizing the $27.1 million excess investment in Seaway on a straight-line basis over a 39-year life related primarily to the life of the pipeline

Table of Contents

TEPPCO PARTNERS, L P
Notes To Consolidated Financial Statements—(Continued)

The following table sets forth the estimated amortization expense of intangible assets and the estimated amortization expense allocated to equity earnings for the years ending December 31 (in thousands)

	Intangible Assets	Excess Investments
2006	$ 32,561	$ 4,691
2007	33,395	5,113
2008	32,967	5,438
2009	30,719	6,878
2010	27,338	7,042

Note 4. Interest Rate Swaps

In July 2000, we entered into an interest rate swap agreement to hedge our exposure to increases in the benchmark interest rate underlying our variable rate revolving credit facility This interest rate swap matured in April 2004 We designated this swap agreement, which hedged exposure to variability in expected future cash flows attributed to changes in interest rates, as a ~~cash flow hedge. The swap agreement was based on a notional amount of $250.0 million. Under the swap agreement, we paid a fixed rate of interest of 6.955% and received a floating rate~~ based on a three-month U S Dollar LIBOR rate Because this swap was designated as a cash flow hedge, the changes in fair value, to the extent the swap was effective, were recognized in other comprehensive income until the hedged interest costs were recognized in earnings During the years ended December 31, 2004 and 2003, we recognized an increase in interest expense of $2 9 million and $14 4 million, respectively, related to the difference between the fixed rate and the floating rate of interest on the interest rate swap

In October 2001, TE Products entered into an interest rate swap agreement to hedge its exposure to changes in the fair value of its fixed rate 7 51% Senior Notes due 2028 We designated this swap agreement as a fair value hedge The swap agreement has a notional amount of $210.0 million and matures in January 2028 to match the principal and maturity of the TE Products Senior Notes Under the swap agreement, TE Products pays a floating rate of interest based on a three-month U.S Dollar LIBOR rate, plus a spread, and receives a fixed rate of interest of 7.51% During the years ended December 31, 2005, 2004 and 2003, we recognized reductions in interest expense of $5 6 million, $9 6 million and $10 0 million, respectively, related to the difference between the fixed rate and the floating rate of interest on the interest rate swap During the years ended December 31, 2005, 2004 and 2003, we measured the hedge effectiveness of this interest rate swap and noted that no gain or loss from ineffectiveness was required to be recognized The fair value of this interest rate swap was a loss of approximately $0 9 million at December 31, 2005, and a gain of approximately $3 4 million at December 31, 2004

During 2002, we entered into interest rate swap agreements, designated as fair value hedges, to hedge our exposure to changes in the fair value of our fixed rate 7 625% Senior Notes due 2012 The swap agreements had a combined notional amount of $500 0 million and matured in 2012 to match the principal and maturity of the Senior Notes Under the swap agreements, we paid a floating rate of interest based on a U S Dollar LIBOR rate, plus a spread, and received a fixed rate of interest of 7 625% These swap agreements were later terminated in 2002 resulting in gains of $44 9 million The gains realized from the swap terminations have been deferred as adjustments to the carrying value of the Senior Notes and are being amortized using the effective interest method as reductions to future interest expense over the remaining term of the Senior Notes At December 31, 2005, the unamortized balance of the deferred gains was $32 4 million In the event of early extinguishment of the Senior Notes, any remaining unamortized gains would be recognized in the consolidated statement of income at the time of extinguishment

During May 2005, we executed a treasury rate lock agreement with a notional amount of $200 0 million to hedge our exposure to increases in the treasury rate that was to be used to establish the fixed interest rate for a debt offering that was proposed to occur in the second quarter of 2005 During June 2005, the proposed debt offering was cancelled, and the treasury lock was terminated with a realized loss of $2 0 million The realized loss was recorded as a component of interest expense in the consolidated statements of income in June 2005

Note 5. Acquisitions, Dispositions and Discontinued Operations

Rancho Pipeline

In connection with our acquisition of crude oil assets in 2000, we acquired an approximate 23 5% undivided joint interest in the Rancho Pipeline, which was a crude oil pipeline system from West Texas to Houston, Texas In March 2003, the Rancho Pipeline ceased operations, and segments of the pipeline were sold to certain of the owners that previously held undivided interests in the pipeline We acquired 241 miles of the pipeline in exchange for cash of $5 5 million and our interests in other portions of the Rancho Pipeline We sold 183 miles of the segment we acquired to other entities for cash and assets valued at approximately $8 5 million We recorded a net gain

TEPPCO PARTNERS, L P

Notes To Consolidated Financial Statements—(Continued)

of $3 9 million on the transactions in the second quarter of 2003 During the third quarter of 2004, we sold our remaining interest in the original Rancho Pipeline system for a net gain of $0 4 million These gains are included in the gains on sales of assets in our consolidated statements of income in the 2004 period

Genesis Pipeline

On November 1, 2003, we purchased crude supply and transportation assets along the upper Texas Gulf Coast for $21 0 million from Genesis Crude Oil, L P and Genesis Pipeline Texas, L P ("Genesis") The transaction was funded with proceeds from our August 2003 equity offering (see Note 11) We allocated the purchase price, net of liabilities assumed, primarily to property, plant and equipment and intangible assets The assets acquired included approximately 150 miles of small diameter trunk lines, 26,000 barrels per day of throughput and 12,000 barrels per day of lease marketing and supply business We have integrated these assets into our South Texas pipeline system, which has allowed us to consolidate gathering and marketing assets in key operating areas in a cost effective manner and will provide future growth opportunities Accordingly, the results of the acquisition are included in the consolidated financial statements from November 1, 2003

The following table allocates the estimated fair value of the Genesis assets acquired on November 1, 2003 (in thousands):

Property, plant and equipment	$	12,811
Intangible assets		8,742
Other		144
Total assets		21,697
Total liabilities assumed		(687)
Net assets acquired	$	21,010

Mexia Pipeline

On March 31, 2005, we purchased crude oil pipeline assets for $7 1 million from BP Pipelines (North America) Inc ("BP") The assets include approximately 158 miles of pipeline, which extend from Mexia, Texas, to the Houston, Texas, area and two stations in south Houston with connections to a BP pipeline that originates in south Houston We funded the purchase through borrowings under our revolving credit facility We allocated the purchase price to property, plant and equipment, and we accounted for the acquisition of these assets under the purchase method of accounting We have integrated these assets into our South Texas pipeline system, included in our Upstream Segment, which will allow us to realize synergies within our existing asset base and will provide future growth opportunities

Crude Oil Storage and Terminaling Assets

On April 1, 2005, we purchased crude oil storage and terminaling assets in Cushing, Oklahoma, from Koch Supply & Trading, L P for $35 4 million The assets consist of eight storage tanks with 945,000 barrels of storage capacity, receipt and delivery manifolds, interconnections to several pipelines, crude oil inventory and approximately 70 acres of land We funded the purchase through borrowings under our revolving credit facility We allocated the purchase price to property, plant and equipment and inventory, and we accounted for the acquisition of these assets under the purchase method of accounting The storage and terminaling assets complement our existing infrastructure in Cushing and strengthen our gathering and marketing business in our Upstream Segment

Refined Products Terminal and Truck Rack

On July 12, 2005, we purchased a refined products terminal and truck loading rack in North Little Rock, Arkansas, for $6 9 million from ExxonMobil Corporation The assets include three storage tanks and a two-bay truck loading rack We funded the purchase through borrowings under our revolving credit facility We allocated the purchase price to property, plant and equipment and inventory, and we accounted for the acquisition of these assets under the purchase method of accounting The terminal serves the central Arkansas refined products market and complements our existing Downstream Segment infrastructure in North Little Rock, Arkansas

Genco Assets

On July 15, 2005, we acquired from Texas Genco, LLC ("Genco") all of its interests in certain companies that own a 90-mile pipeline system and 5 5 million barrels of storage capacity for $62 1 million We funded the purchase through borrowings under our revolving credit facility We allocated the purchase price to property, plant and equipment, and we accounted for the acquisition of these assets under the purchase method of accounting The assets of the purchased companies will be integrated into our Downstream Segment

TEPPCO PARTNERS, L P

Notes To Consolidated Financial Statements—(Continued)

origin infrastructure in Texas City and Baytown, Texas As a result of this acquisition, we initiated the expansion of refined products origin capabilities in the Houston and Texas City, Texas, areas The integration and other system enhancements should be in service by the fourth quarter of 2006, at an estimated cost of $45 0 million The strategic location of these assets, with refined products interconnections to major exchange terminals in the Houston area, will provide significant long-term value to our customers and our Texas Gulf Coast refining and logistics system

Pioneer Plant

On January 26, 2006, we announced the execution of a letter of intent to sell our ownership interest in the Pioneer silica gel natural gas processing plant located near Opal, Wyoming, together with Jonah's rights to process natural gas originating from the Jonah and Pinedale fields, located in southwest Wyoming, to an affiliate of Enterprise Products Partners L P ("Enterprise"). On March 31, 2006, we sold the Pioneer plant to an affiliate of Enterprise for $38 0 million in cash The Pioneer plant, included in our Midstream Segment, was not an integral part of our operations and natural gas processing is not a core business The Pioneer plant was constructed as part of the Phase III expansion of the Jonah system and was completed during the first quarter of 2004 We have no continuing involvement in the operations or results of this plant This transaction was reviewed and approved by the Audit and Conflicts Committee of the board of directors of our General Partner and of the general partner of Enterprise, and a fairness opinion was rendered by an independent third-party.

Condensed statements of income for the Pioneer plant, which is classified as discontinued operations, for the years ended December 31, 2005 and 2004, are presented below (in thousands):

	Years Ended December 31, 2005	Years Ended December 31, 2004
Sales of petroleum products	$ 10,479	$ 7,295
Other	2,975	2,807
Total operating revenues	13,454	10,102
Purchases of petroleum products	8,870	5,944
Operating, general and administrative	692	738
Depreciation and amortization	612	610
Taxes—other than income taxes	130	121
Total costs and expenses	10,304	7,413
Income from discontinued operations	$ 3,150	$ 2,689

Assets of the discontinued operations consisted of the following at December 31, 2005 and 2004 (in thousands):

	December 31, 2005	December 31, 2004
Inventories	$ 7	$ 28
Property, plant and equipment, net	19,812	20,598
Assets of discontinued operations	$ 19,819	$ 20,626

Net cash flows from discontinued operations for the years ended December 31, 2005 and 2004, are presented below (in thousands):

	Years Ended December 31, 2005	2004	2003
Cash flows from discontinued operating activities:			
Net income	$ 3,150	$ 2,689	$ —
Depreciation and amortization	612	610	—
(Increase) decrease in inventories	20	(28)	—
Net cash flows provided by discontinued operating activities	3,782	3,271	—
Cash flows from discontinued investing activities:			
Capital expenditures	—	(7,398)	(13,810)
Net cash flows used in discontinued investing activities	—	(7,398)	(13,810)
Net cash flows from discontinued operations	$ 3,782	$ (4,127)	$ (13,810)

TEPPCO PARTNERS, L P

Notes To Consolidated Financial Statements—(Continued)

Note 6. Equity Investments

Through one of our indirect wholly owned subsidiaries, we own a 50% ownership interest in Seaway The remaining 50% interest is owned by ConocoPhillips We operate the Seaway assets Seaway owns a pipeline that carries mostly imported crude oil from a marine terminal at Freeport, Texas, to Cushing, Oklahoma, and from a marine terminal at Texas City, Texas, to refineries in the Texas City and Houston, Texas, areas The Seaway Crude Pipeline Company Partnership Agreement provides for varying participation ratios throughout the life of Seaway From June 2002 through May 2006, we receive 60% of revenue and expense of Seaway Thereafter, we will receive 40% of revenue and expense of Seaway During the years ended December 31, 2005, 2004 and 2003, we received distributions from Seaway of $24 7 million, $36 9 million and $22 7 million, respectively

In August 2000, TE Products entered into agreements with Panhandle Eastern Pipeline Company ("PEPL"), a former subsidiary of CMS Energy Corporation, and Marathon Petroleum Company LLC ("Marathon") to form Centennial Centennial owns an interstate refined petroleum products pipeline extending from the upper Texas Gulf Coast to central Illinois Through February 9, 2003, each participant owned a one-third interest in Centennial On February 10, 2003, TE Products and Marathon each acquired an additional 16 7% interest in Centennial from PEPL for $20 0 million each, increasing their ownership percentages in Centennial to 50% each During the year ended December 31, 2005, TE Products did not make any additional investments in Centennial TE Products invested an additional $1 5 million and $24 0 million, respectively, in Centennial, in 2004 and 2003, which is included in the equity investment balance at December 31, 2005 The 2003 amount includes the $20 0 million paid for the acquisition of the additional ownership interest in Centennial TE Products has not received any distributions from Centennial since its formation.

On January 1, 2003, TE Products and Louis Dreyfus Energy Services L P ("Louis Dreyfus") formed Mont Belvieu Storage Partners, L P ("MB Storage") TE Products and Louis Dreyfus each own a 50% ownership interest in MB Storage MB Storage owns storage capacity at the Mont Belvieu fractionation and storage complex and a short haul transportation shuttle system that ties Mont Belvieu, Texas, to the upper Texas Gulf Coast energy marketplace MB Storage is a service-oriented, fee-based venture serving the fractionation, refining and petrochemical industries with substantial capacity and flexibility for the transportation, terminaling and storage of NGLs, LPGs and refined products MB Storage has no commodity trading activity TE Products operates the facilities for MB Storage Effective January 1, 2003, TE Products contributed property and equipment with a net book value of $67 1 million to MB Storage Additionally, as of the contribution date, Louis Dreyfus had invested $6 1 million for expansion projects for MB Storage that TE Products was required to reimburse if the original joint development and marketing agreement was terminated by either party This deferred liability was also contributed and credited to the capital account of Louis Dreyfus in MB Storage

For the year ended December 31, 2005, TE Products received the first $1.7 million per quarter (or $6.78 million on an annual basis) of MB Storage's income before depreciation expense, as defined in the operating agreement For the year ended December 31, 2004, TE Products received the first $1 8 million per quarter (or $7 15 million on an annual basis) of MB Storage's income before depreciation expense TE Products' share of MB Storage's earnings is adjusted annually by the partners of MB Storage Any amount of MB Storage's annual income before depreciation expense in excess of $6 78 million for 2005 and $7 15 million for 2004 was allocated evenly between TE Products and Louis Dreyfus Depreciation expense on assets each party originally contributed to MB Storage is allocated between TE Products and Louis Dreyfus based on the net book value of the assets contributed Depreciation expense on assets constructed or acquired by MB Storage subsequent to formation is allocated evenly between TE Products and Louis Dreyfus For the years ended December 31, 2005, 2004 and 2003, TE Products' sharing ratio in the earnings of MB Storage was 64 2%, 69 4% and 70 4%, respectively During the years ended December 31, 2005, 2004 and 2003, TE Products received distributions of $12 4 million, $10 3 million and $5 3 million, respectively, from MB Storage During the years ended December 31, 2005, 2004 and 2003, TE Products contributed $5 6 million, $21 4 million and $2 5 million, respectively, to MB Storage The 2005 contribution includes a combination of non-cash asset transfers of $1 4 million and cash contributions of $4 2 million The 2004 contribution includes $16 5 million for the acquisition of storage and pipeline assets in April 2004 The remaining contributions have been for capital expenditures

We use the equity method of accounting to account for our investments in Seaway, Centennial and MB Storage Summarized combined financial information for Seaway, Centennial and MB Storage for the years ended December 31, 2005 and 2004, is presented below (in thousands):

	Years Ended December 31, 2005	Years Ended December 31, 2004
Revenues	$ 164,494	$ 149,843
Net income	52,623	52,059

TEPPCO PARTNERS, L.P.

Notes To Consolidated Financial Statements—(Continued)

Summarized combined balance sheet information for Seaway, Centennial and MB Storage as of December 31, 2005 and 2004, is presented below (in thousands):

	December 31, 2005	December 31, 2004
Current assets	$ 60,082	$ 59,314
Noncurrent assets	630,212	633,222
Current liabilities	42,242	41,209
Long-term debt	140,000	140,000
Noncurrent liabilities	13,626	20,440
Partners' capital	494,426	490,887

Note 7. Related Party Transactions

EPCO and Affiliates and Duke Energy, DEFS and Affiliates

The Partnership does not have any employees. We are managed by the Company, which, for all periods prior to February 23, 2005, was an indirect wholly owned subsidiary of DEFS. According to the Partnership Agreement, the Company was entitled to reimbursement of all direct and indirect expenses related to our business activities. As a result of the change in ownership of the General Partner on February 24, 2005, all of our management, administrative and operating functions are performed by employees of EPCO, pursuant to an administrative services agreement. We reimburse EPCO for the costs of its employees who perform operating functions for us and for costs related to its other management and administrative employees (see Note 1).

The following table summarizes the related party transactions with EPCO and affiliates and DEFS and affiliates for the periods indicated (in millions):

	Years Ended December 31, 2005	2004	2003
Revenues from EPCO and affiliates(1)			
Transportation—NGLs(2)	$ 7.4	$ —	$ —
Transportation—LPGs(3)	4.3	—	—
Other operating revenues(4)	0.3	—	—
Costs and Expenses from EPCO and affiliates(1)			
Payroll and administrative(5)	68.2	—	—
Purchases of petroleum products(6)	3.4	—	—
Revenues from DEFS and affiliates(7)			
Sales of petroleum products(8)	4.3	23.2	15.2
Transportation—NGLs(9)	2.8	16.7	17.2
Gathering—Natural gas—Jonah(10)	0.5	3.3	2.0
Transportation—LPGs(11)	0.7	2.6	2.8
Other operating revenues(12)	2.4	14.0	10.8
Costs and Expenses from DEFS and affiliates(7) (13) (14)			
Payroll and administrative(5)	16.2	95.9	88.8
Purchases of petroleum products—TCO(15)	37.7	141.3	110.7
Purchases of petroleum products—Jonah(16)	0.8	5.1	—

(1) Operating revenues earned and expenses incurred from activities with EPCO and its affiliates are considered related party transactions from February 24, 2005, through December 31, 2005, as a result of the change in ownership of the General Partner (see Note 1).

(2) Includes revenues from NGL transportation on the Chaparral and Panola NGL pipelines.

(3) Includes revenues from LPG transportation on the TE Products pipeline.

(4) Includes other operating revenues on TE Products.

(5) Substantially all of these costs were related to payroll, payroll related expenses and administrative expenses incurred in managing us and our subsidiaries.

(6) Includes TCO purchases of condensate and expenses related to LSI's use of an affiliate of EPCO as a transporter.

(7) Operating revenues earned and expenses incurred from activities with DEFS and its affiliates are considered related party transactions for all periods through February 23, 2005, as a result of the change in ownership of the General Partner (see Note 1).

(8) Includes LSI sales of lubrication oils and specialty chemicals and Jonah NGL sales in connection with Jonah's Pioneer processing plant operations, which was constructed during the Phase III expansion and began operating in 2004. Amounts related to the Pioneer plant are classified as discontinued operations in the consolidated statements of income.

(9) Includes revenues from NGL transportation on the Chaparral, Panola, Dean and Wilcox NGL pipelines.

(10) Includes gas gathering revenues on the Jonah system.

(11) Effective May 2001, we entered into an agreement with an affiliate of DEFS to commit to it sole utilization of our Providence, Rhode Island, terminal. We operate the terminal and provide propane loading services to an affiliate of DEFS. We recognized revenue from an affiliate of DEFS pursuant to this agreement.

(12) Includes fractionation revenues and other revenues. Effective with the purchase of the fractionation facilities on March 31, 1998, TEPPCO Colorado and DEFS entered into a 20-year Fractionation Agreement, under which TEPPCO Colorado receives a variable fee for all fractionated volumes delivered to DEFS. Other operating revenues also include other operating revenues on TE Products and processing and other revenues on the Jonah system. Amounts related to the Pioneer plant are classified as discontinued operations in the consolidated statements of income.

TEPPCO PARTNERS, L P

Notes To Consolidated Financial Statements—(Continued)

(13) Includes operating costs and expenses related to DEFS managing and operating the Jonah and Val Verde systems and the Chaparral NGL pipeline on our behalf under a contractual agreement established at the time of acquisition of each asset In connection with the change in ownership of our General Partner, we have assumed these activities

(14) Effective with the purchase of the fractionation facilities on March 31, 1998, TEPPCO Colorado and DEFS entered into an Operation and Maintenance Agreement, whereby DEFS operates and maintains the fractionation facilities for TEPPCO Colorado For these services, TEPPCO Colorado pays DEFS a set volumetric rate for all fractionated volumes delivered to DEFS

(15) Includes TCO purchases of condensate

(16) Includes Jonah purchases of natural gas in connection with Jonah's Pioneer processing plant operations

At December 31, 2005, we had a receivable from EPCO and affiliates of $4 3 million related to sales and transportation services provided to EPCO and affiliates At December 31, 2005, we had a payable to EPCO and affiliates of $9 8 million related to direct payroll, payroll related costs and other operational related charges

At December 31, 2004, we had a receivable from DEFS and affiliates of $10 5 million related to sales and transportation services provided to DEFS and affiliates Included in this receivable balance from DEFS and affiliates at December 31, 2004, is a gas imbalance receivable of $0 9 million At December 31, 2004, we had a payable to DEFS and affiliates of $22 4 million related to direct payroll, payroll related costs, management fees, and other operational related charges, including those for Jonah, Chaparral and Val Verde as described above Included in this payable balance at December 31, 2004, is a gas imbalance payable to DEFS and affiliates of $3 2 million

From February 24, 2005 through December 31, 2005, the majority of our insurance coverage, including property, liability, business interruption, auto and directors and officers' liability insurance, was obtained through EPCO From February 24, 2005 through December 31, 2005, we incurred insurance expense related to premiums charged by EPCO of $9 8 million At December 31, 2005, we had insurance reimbursement receivables due from EPCO of $1 3 million

Through February 23, 2005, we contracted with Bison Insurance Company Limited ("Bison"), a wholly owned subsidiary of Duke Energy, for a majority of our insurance coverage, including property, liability, auto and directors and officers' liability insurance Through February 23, 2005 and for the years ended December 31, 2004 and 2003, we incurred insurance expense related to premiums paid to Bison of $1 2 million, $6 5 million and $5 9 million, respectively At December 31, 2004, we had insurance reimbursement receivables due from Bison of $5 2 million

On April 2, 2003, we sold in an underwritten public offering 3 9 million Units at $30 35 per Unit The proceeds from the offering, net of underwriting discount, totaled approximately $114 5 million, of which approximately $113 8 million was used to repurchase and retire all of the 3 9 million previously outstanding Class B Units held by DETTCO (see Note 11)

Seaway

We own a 50% ownership interest in Seaway, and the remaining 50% interest is owned by ConocoPhillips (see Note 6) We operate the Seaway assets During the years ended December 31, 2005, 2004 and 2003, we billed Seaway $8 5 million, $7 6 million and $7 4 million, respectively, for direct payroll and payroll related expenses for operating Seaway Additionally, for each of the years ended December 31, 2005, 2004 and 2003, we billed Seaway $2 1 million for indirect management fees for operating Seaway At December 31, 2005 and 2004, we had payable balances to Seaway of $0 6 million and $0 5 million, respectively, for advances Seaway paid to us as operator for operating costs, including payroll and related expenses and management fees

Centennial

TE Products has a 50% ownership interest in Centennial (see Note 6) TE Products has entered into a management agreement with Centennial to operate Centennial's terminal at Creal Springs, Illinois, and pipeline connection in Beaumont, Texas For each of the years ended December 31, 2005, 2004 and 2003, we recognized management fees of $0 2 million from Centennial, and actual operating expenses billed to Centennial were $3 7 million, $6 9 million and $4 4 million, respectively

TE Products also has a joint tariff with Centennial to deliver products at TE Products' locations using Centennial's pipeline as part of the delivery route to connecting carriers TE Products, as the delivering pipeline, invoices the shippers for the entire delivery rate, records only the net rate attributable to it as transportation revenues and records a liability for the amounts due to Centennial for its share of the tariff In addition, TE Products performs ongoing construction services for Centennial and bills Centennial for labor and other costs to perform the construction At December 31, 2005 and 2004, we had net payable balances of $1 4 million and $1 7 million, respectively, to Centennial for its share of the joint tariff deliveries and other operational related charges, partially offset by the reimbursement due to us for construction services provided to Centennial

In January 2003, TE Products entered into a pipeline capacity lease agreement with Centennial for a period of five years that contains a minimum throughput requirement For the years ended December 31, 2005, 2004 and 2003, TE Products incurred $5 9 million, $5 3 million and $3 8 million, respectively, of rental charges related to the lease of pipeline capacity on Centennial

TEPPCO PARTNERS, L.P.
Notes To Consolidated Financial Statements—(Continued)

MB Storage

Effective January 1, 2003, TE Products entered into agreements with Louis Dreyfus to form MB Storage (see Note 6). TE Products operates the facilities for MB Storage. TE Products and MB Storage have entered into a pipeline capacity lease agreement, and for each of the years ended December 31, 2005, 2004 and 2003, TE Products recognized $0.1 million in rental revenue related to this lease agreement. During the years ended December 31, 2005, 2004 and 2003, TE Products also billed MB Storage $3.6 million, $3.2 million and $2.5 million, respectively, for direct payroll and payroll related expenses for operating MB Storage. At December 31, 2005 and 2004, TE Products had net receivable balances from MB Storage of $0.9 million and $1.3 million, respectively, for operating costs, including payroll and related expenses for operating MB Storage.

Note 8. Inventories

Inventories are valued at the lower of cost (based on weighted average cost method) or market. The costs of inventories did not exceed market values at December 31, 2005 and 2004. The major components of inventories were as follows (in thousands):

	December 31,	
	2005	2004
Crude oil	$ 3,021	$ 3,690
Refined products	4,461	5,665
LPGs	7,403	—
Lubrication oils and specialty chemicals	5,740	4,002
Materials and supplies	8,203	6,135
Other	241	29
Total	$ 29,069	$ 19,521

Note 9. Property, Plant and Equipment

Major categories of property, plant and equipment for the years ended December 31, 2005 and 2004, were as follows (in thousands):

	December 31,	
	2005	2004
Land and right of way	$ 147,064	$ 135,984
Line pipe and fittings	1,434,392	1,344,193
Storage tanks	189,054	140,690
Buildings and improvements	51,596	41,205
Machinery and equipment	370,439	333,363
Construction work in progress	241,855	115,937
Total property, plant and equipment	$ 2,434,400	$ 2,111,372
Less accumulated depreciation and amortization	474,332	407,670
Net property, plant and equipment	$ 1,960,068	$ 1,703,702

Depreciation expense, including impairment charges, on property, plant and equipment was $80.8 million, $80.7 million and $64.5 million for the years ended December 31, 2005, 2004 and 2003, respectively. During the fourth quarter of 2004, we wrote off approximately $2.1 million in assets taken out of service to depreciation expense.

In September 2005, our Todhunter facility, near Middletown, Ohio, experienced a propane release and fire at a dehydration unit within the storage facility. The facility is included in our Downstream Segment. The dehydration unit was destroyed due to the propane release and fire, and as a result, we wrote off the remaining book value of the asset of $0.8 million to depreciation and amortization expense during the third quarter of 2005.

We evaluate impairment of long-lived assets in accordance with SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*. During the third quarter of 2005, our Upstream Segment was notified by a connecting carrier that the flow of its pipeline system would be reversed, which would directly impact the viability of one of our pipeline systems. This system, located in East Texas, consists of approximately 45 miles of pipeline, six tanks of various sizes and other equipment and asset costs. As a result of changes to the connecting carrier, we performed an impairment test of the system and recorded a $1.8 million non-cash impairment charge.

TEPPCO PARTNERS, L.P.
Notes To Consolidated Financial Statements—(Continued)

included in depreciation and amortization expense in our consolidated statements of income, for the excess carrying value over the estimated fair value of the system.

During the third quarter of 2005, we completed an evaluation of a crude oil system included in our Upstream Segment. The system, located in Oklahoma, consists of approximately six miles of pipelines, tanks and other equipment and asset costs. The usage of the system has declined in recent months as a result of shifting crude oil production into areas not supported by the system, and as such, it has become more economical to transport barrels by truck to our other pipeline systems. As a result, we performed an impairment test on the system and recorded a $0.8 million non-cash impairment charge, included in depreciation and amortization expense in our consolidated statements of income, for the excess carrying value over the estimated fair value of the system.

During the third quarter of 2004, we completed an evaluation of our marine terminal facility in the Beaumont, Texas, area. The facility consists primarily of a barge dock, a ship dock, four storage tanks and various segments of connecting pipelines and is included in our Downstream Segment. The evaluation indicated that the docks and other assets at the facility needed extensive work to continue to be commercially operational. As a result, we performed an impairment test on the entire marine facility and recorded a $4.4 million non-cash impairment charge, included in depreciation and amortization expense in our consolidated statements of income, for the excess carrying value over the estimated fair value of the facility.

Note 10. Debt

Senior Notes. On January 27, 1998, TE Products completed the issuance of $180.0 million principal amount of 6.45% Senior Notes due 2008, and $210.0 million principal amount of 7.51% Senior Notes due 2028 (collectively the "TE Products Senior Notes"). The 6.45% TE Products Senior Notes were issued at a discount of $0.3 million and are being accreted to their face value over the term of the notes. The 6.45% TE Products Senior Notes due 2008 are not subject to redemption prior to January 15, 2008. The 7.51% TE Products Senior Notes due 2028, issued at par, may be redeemed at any time after January 15, 2008, at the option of TE Products, in whole or in part, at our election at the following redemption prices (expressed in percentages of the principal amount) if redeemed during the twelve months beginning January 15 of the years indicated:

Year	Redemption Price	Year	Redemption Price
2008	103.755%	2013	101.878%
2009	103.380%	2014	101.502%
2010	103.004%	2015	101.127%
2011	102.629%	2016	100.751%
2012	102.253%	2017	100.376%

and thereafter at 100% of the principal amount, together in each case with accrued interest at the redemption date.

The TE Products Senior Notes do not have sinking fund requirements. Interest on the TE Products Senior Notes is payable semiannually in arrears on January 15 and July 15 of each year. The TE Products Senior Notes are unsecured obligations of TE Products and rank pari passu with all other unsecured and unsubordinated indebtedness of TE Products. The indenture governing the TE Products Senior Notes contains covenants, including, but not limited to, covenants limiting the creation of liens securing indebtedness and sale and leaseback transactions. However, the indenture does not limit our ability to incur additional indebtedness. As of December 31, 2005, TE Products was in compliance with the covenants of the TE Products Senior Notes.

On February 20, 2002, we completed the issuance of $500.0 million principal amount of 7.625% Senior Notes due 2012. The 7.625% Senior Notes were issued at a discount of $2.2 million and are being accreted to their face value over the term of the notes. The Senior Notes may be redeemed at any time at our option with the payment of accrued interest and a make-whole premium determined by discounting remaining interest and principal payments using a discount rate equal to the rate of the United States Treasury securities of comparable remaining maturity plus 35 basis points. The indenture governing our 7.625% Senior Notes contains covenants, including, but not limited to, covenants limiting the creation of liens securing indebtedness and sale and leaseback transactions. However, the indenture does not limit our ability to incur additional indebtedness. As of December 31, 2005, we were in compliance with the covenants of these Senior Notes.

On January 30, 2003, we completed the issuance of $200.0 million principal amount of 6.125% Senior Notes due 2013. The 6.125% Senior Notes were issued at a discount of $1.4 million and are being accreted to their face value over the term of the notes. The Senior Notes may be redeemed at any time at our option with the payment of accrued interest and a make-whole premium determined by discounting remaining interest and principal payments using a discount rate equal to the rate of the United States Treasury securities of comparable remaining maturity plus 35 basis points. The indenture governing our 6.125% Senior Notes contains covenants, including, but not limited to, covenants limiting the creation of liens securing indebtedness and sale and leaseback transactions. However, the indenture does not limit our ability to incur additional indebtedness. As of December 31, 2005, we were in compliance with the covenants of these Senior Notes.

TEPPCO PARTNERS, L P
Notes To Consolidated Financial Statements—(Continued)

not limited to, covenants limiting the creation of liens securing indebtedness and sale and leaseback transactions However, the indenture does not limit our ability to incur additional indebtedness As of December 31, 2005, we were in compliance with the covenants of these Senior Notes

The following table summarizes the estimated fair values of the Senior Notes as of December 31, 2005 and 2004 (in millions):

	Face Value	Fair Value December 31, 2005	Fair Value December 31, 2004
6.45% TE Products Senior Notes, due January 2008	$ 180.0	$ 183.7	$ 187.1
7 625% Senior Notes, due February 2012	500 0	552 0	569 6
6.125% Senior Notes, due February 2013	200.0	205.6	210.2
7 51% TE Products Senior Notes, due January 2028	210 0	224 1	225 6

We have entered into interest rate swap agreements to hedge our exposure to changes in the fair value on a portion of the Senior Notes discussed above (see Note 4).

Revolving Credit Facility. On April 6, 2001, we entered into a $500 0 million revolving credit facility including the issuance of letters of credit of up to $20 0 million ("Three Year Facility"). The interest rate was based, at our option, on either the lender's base rate plus a spread, or LIBOR plus a spread in effect at the time of the borrowings. The credit agreement for the Three Year Facility contained certain restrictive financial covenant ratios During the first quarter of 2003, we repaid $182 0 million of the outstanding balance of the Three Year Facility with proceeds from the issuance of our 6 125% Senior Notes on January 30, 2003 On June 27, 2003, we repaid the outstanding balance under the Three Year Facility with borrowings under a new credit facility, and canceled the Three Year Facility

On June 27, 2003, we entered into a $550 0 million unsecured revolving credit facility with a three year term, including the issuance of letters of credit of up to $20 0 million ("Revolving Credit Facility") The interest rate is based, at our option, on either the lender's base rate plus a spread, or LIBOR plus a spread in effect at the time of the borrowings The credit agreement for the Revolving Credit Facility contains certain restrictive financial covenant ratios Restrictive covenants in the Revolving Credit Facility limit our ability to, among other things, incur additional indebtedness, make distributions in excess of Available Cash (see Note 11) and complete mergers, acquisitions and sales of assets We borrowed $263 0 million under the Revolving Credit Facility and repaid the outstanding balance of the Three Year Facility On October 21, 2004, we amended our Revolving Credit Facility to (i) increase the facility size to $600 0 million, (ii) extend the term to October 21, 2009, (iii) remove certain restrictive covenants, (iv) increase the available amount for the issuance of letters of credit up to $100 0 million and (v) decrease the LIBOR rate spread charged at the time of each borrowing On February 23, 2005, we amended our Revolving Credit Facility to remove the requirement that DEFS must at all times own, directly or indirectly, 100% of our General Partner, to allow for its acquisition by DFI (see Note 1) During the second quarter of 2005, we used a portion of the proceeds from the equity offering in May 2005 to repay a portion of the Revolving Credit Facility (see Note 11) On December 13, 2005, we again amended our Revolving Credit Facility as follows:

- Total bank commitments increased from $600 0 million to $700 0 million The amendment also provided that the commitments under the credit facility may be increased up to a maximum of $850 0 million upon our request, subject to lender approval and the satisfaction of certain other conditions
- The facility fee and the borrowing rate currently in effect were reduced by 0 275%
- The maturity date of the credit facility was extended from October 21, 2009, to December 13, 2010 Also under the terms of the amendment, we may request up to two, one-year extensions of the maturity date These extensions, if requested, will become effective subject to lender approval and satisfaction of certain other conditions
- The amendment also removed the $100 0 million limit on the total amount of standby letters of credit that can be outstanding under the credit facility

On December 31, 2005, $405 9 million was outstanding under the Revolving Credit Facility at a weighted average interest rate of 4 9% At December 31, 2005, we were in compliance with the covenants of this credit agreement.

TEPPCO PARTNERS, L P

Notes To Consolidated Financial Statements—(Continued)

The following table summarizes the principal amounts outstanding under all of our credit facilities as of December 31, 2005 and 2004 (in thousands)

	December 31, 2005	December 31, 2004
Credit Facilities:		
Revolving Credit Facility, due December 2010	$ 405,900	$ 353,000
6.45% TE Products Senior Notes, due January 2008	179,937	179,906
7 625% Senior Notes, due February 2012	498,659	498,438
6.125% Senior Notes, due February 2013	198,988	198,845
7 51% TE Products Senior Notes, due January 2028	210,000	210,000
Total borrowings	1,493,484	1,440,189
Adjustment to carrying value associated with hedges of fair value	31,537	40,037
Total Credit Facilities	$ 1,525,021	$ 1,480,226

Letter of Credit. At December 31, 2005, we had an $11 5 million standby letter of credit in connection with crude oil purchases in the fourth quarter of 2005 This amount will be paid during the first quarter of 2006

Note 11. Partners' Capital and Distributions

Equity Offerings

On April 2, 2003, we sold in an underwritten public offering 3 9 million Units at $30 35 per Unit The proceeds from the offering, net of underwriting discount, totaled approximately $114 5 million, of which approximately $113 8 million was used to repurchase and retire all of the 3 9 million previously outstanding Class B Units held by DETTCO We received approximately $0 7 million in proceeds from the offering in excess of the amount needed to repurchase and retire the Class B Units

On August 7, 2003, we sold in an underwritten public offering 5 0 million Units at $34 68 per Unit The proceeds from the offering, net of underwriting discount, totaled approximately $166 0 million On August 19, 2003, 162,900 Units were sold upon exercise of the underwriters' over-allotment option granted in connection with the offering on August 7, 2003 Proceeds from the over-allotment sale, net of underwriting discount, totaled $5 4 million Approximately $53 0 million of the proceeds were used to repay indebtedness under our revolving credit facility and $21 0 million was used to fund the acquisition of the Genesis assets (see Note 5). The remaining amount was used primarily to fund revenue-generating and system upgrade capital expenditures and for general partnership purposes

On May 5, 2005, we sold in an underwritten public offering 6 1 million Units at $41 75 per Unit The proceeds from the offering, net of underwriting discount, totaled approximately $244 5 million On June 8, 2005, 865,000 Units were sold upon exercise of the underwriters' over-allotment option granted in connection with the offering on May 5, 2005 Proceeds from the over-allotment sale, net of underwriting discount, totaled $34 7 million The proceeds were used to reduce indebtedness under our Revolving Credit Facility, to fund revenue generating and system upgrade capital expenditures and for general partnership purposes

Quarterly Distributions of Available Cash

We make quarterly cash distributions of all of our Available Cash, generally defined as consolidated cash receipts less consolidated cash disbursements and cash reserves established by the General Partner in its sole discretion Pursuant to the Partnership Agreement, the General Partner receives incremental incentive cash distributions when unitholders' cash distributions exceed certain target thresholds as follows:

	Unitholders	General Partner
Quarterly Cash Distribution per Unit:		
Up to Minimum Quarterly Distribution ($0 275 per Unit)	98%	2%
First Target—$0 276 per Unit up to $0.325 per Unit	85%	15%
Second Target—$0 326 per Unit up to $0 45 per Unit	75%	25%
Over Second Target—Cash distributions greater than $0.45 per Unit	50%	50%

TEPPCO PARTNERS, L P

Notes To Consolidated Financial Statements—(Continued)

The following table reflects the allocation of total distributions paid during the years ended December 31, 2005, 2004 and 2003 (in thousands, except per Unit amounts):

	Years Ended December 31,		
	2005	2004	2003
Limited Partner Units	$ 177,917	$ 166,158	$ 145,427
General Partner Ownership Interest	3,630	3,391	3,016
General Partner Incentive	69,554	63,508	51,709
Total Partners' Capital Cash Distributions Paid	251,101	233,057	200,152
Class B Units	—	—	2,346
Total Cash Distributions Paid	$ 251,101	$ 233,057	$ 202,498
Total Cash Distributions Paid Per Unit	$ 2.68	$ 2.64	$ 2.50

On February 7, 2006, we paid a cash distribution of $0 675 per Unit for the quarter ended December 31, 2005 The fourth quarter 2005 cash distribution totaled $66 9 million

General Partner Interest

As of December 31, 2005 and 2004, we had deficit balances of $61 5 million and $35 9 million, respectively, in our General Partner's equity account These negative balances do not represent an asset to us and do not represent an obligation of the General Partner to contribute cash or other property to us The General Partner's equity account generally consists of its cumulative share of our net income less cash distributions made to it plus capital contributions that it has made to us (see our Consolidated Statements of Partners' Capital for a detail of the General Partner's equity account) For the years ended December 31, 2005, 2004 and 2003, the General Partner was allocated $47 6 million (representing 29 27%), $40 0 million (representing 28 85%) and $33 7 million (representing 27 65%), respectively, of our net income and received $73 2 million, $66 9 million and $54 7 million, respectively, in cash distributions

Capital Accounts, as defined under our Partnership Agreement, are maintained for our General Partner and our limited partners The Capital Account provisions of our Partnership Agreement incorporate principles established for U S federal income tax purposes and are not comparable to the equity accounts reflected under accounting principles generally accepted in the United States in our financial statements Under our Partnership Agreement, the General Partner is required to make additional capital contributions to us upon the issuance of any additional Units if necessary to maintain a Capital Account balance equal to 1 999999% of the total Capital Accounts of all partners At December 31, 2005 and 2004, the General Partner's Capital Account balance substantially exceeded this requirement

Net income is allocated between the General Partner and the limited partners in the same proportion as aggregate cash distributions made to the General Partner and the limited partners during the period This is generally consistent with the manner of allocating net income under our Partnership Agreement Net income determined under our Partnership Agreement, however, incorporates principles established for U S federal income tax purposes and is not comparable to net income reflected under accounting principles generally accepted in the United States in our financial statements

Cash distributions that we make during a period may exceed our net income for the period We make quarterly cash distributions of all of our Available Cash, generally defined as consolidated cash receipts less consolidated cash disbursements and cash reserves established by the General Partner in its sole discretion Cash distributions in excess of net income allocations and capital contributions during the years ended December 31, 2005 and 2004, resulted in a deficit in the General Partner's equity account at December 31, 2005 and 2004 Future cash distributions that exceed net income will result in an increase in the deficit balance in the General Partner's equity account

According to the Partnership Agreement, in the event of our dissolution, after satisfying our liabilities, our remaining assets would be divided among our limited partners and the General Partner generally in the same proportion as Available Cash but calculated on a cumulative basis over the life of the Partnership If a deficit balance still remains in the General Partner's equity account after all allocations are made between the partners, the General Partner would not be required to make whole any such deficit

Note 12. Concentrations of Credit Risk

Our primary market areas are located in the Northeast, Midwest and Southwest regions of the United States We have a concentration of trade receivable balances due from major integrated oil companies, independent oil companies and other pipelines and wholesalers These concentrations of customers may affect our overall credit risk in that the customers may be similarly affected by changes

TEPPCO PARTNERS, L P
Notes To Consolidated Financial Statements—(Continued)

in economic, regulatory or other factors We thoroughly analyze our customers' historical and future credit positions prior to extending credit We manage our exposure to credit risk through credit analysis, credit approvals, credit limits and monitoring procedures, and for certain transactions may utilize letters of credit, prepayments and guarantees

For each of the years ended December 31, 2005, 2004 and 2003, Valero Energy Corp accounted for 14%, 16% and 16% of our total consolidated revenues, respectively No other single customer accounted for 10% or more of our total consolidated revenues for the years ended December 31, 2005, 2004 and 2003

The carrying amount of cash and cash equivalents, accounts receivable, inventories, other current assets, accounts payable and accrued liabilities, other current liabilities and derivatives approximates their fair value due to their short-term nature

Note 13. Unit-Based Compensation

1994 Long Term Incentive Plan

During 1994, the Company adopted the Texas Eastern Products Pipeline Company 1994 Long Term Incentive Plan ("1994 LTIP") The 1994 LTIP provides certain key employees with an incentive award whereby a participant is granted an option to purchase Units These same employees are also granted a stipulated number of Performance Units, the cash value of which may be used to pay for the exercise of the respective Unit options awarded Under the provisions of the 1994 LTIP, no more than one million options and two million Performance Units may be granted.

When our calendar year earnings per unit (exclusive of certain special items) exceeds a stated threshold, each participant receives a credit to their respective Performance Unit account equal to the earnings per unit excess multiplied by the number of Performance Units awarded The balance in the Performance Unit account may be used to offset the cost of exercising Unit options granted in connection with the Performance Units or may be withdrawn two years after the underlying options expire, usually 10 years from the date of grant Any unused balance previously credited is forfeited upon termination We accrue compensation expense for the Performance Units awarded annually based upon the terms of the plan discussed above

Under the agreement for such Unit options, the options become exercisable in equal installments over periods of one, two, and three years from the date of the grant At December 31, 2005, all options have been fully exercised The Performance Unit account has a minimal liability balance which may be withdrawn by the participants after December 31, 2006

A summary of Unit options granted under the terms of the 1994 LTIP is presented below:

	Options Outstanding	Options Exercisable	Exercise Range
Unit Options:			
Outstanding at December 31, 2002	90,091	90,091	$ 13 81 – $25 69
Exercised	(90,091)	(90,091)	$ 13.81 – $25.69
Outstanding at December 31, 2003	—	—	

We have not granted options for any periods presented During the year ended December 31, 2003, all remaining outstanding Unit options were exercised For options previously outstanding, we followed the intrinsic value method for recognizing stock-based compensation expense The exercise price of all options awarded under the 1994 LTIP equaled the market price of our Units on the date of grant Accordingly, we recognized no compensation expense at the date of grant Had compensation expense been determined consistent with SFAS No 123, *Accounting for Stock-Based Compensation*, no compensation expense would have been recognized for the years ended December 31, 2005, 2004 and 2003

1999 and 2002 Phantom Unit Plans

Effective September 1, 1999, the Company adopted the Texas Eastern Products Pipeline Company, LLC 1999 Phantom Unit Retention Plan ("1999 PURP") Effective June 1, 2002, the Company adopted the Texas Eastern Products Pipeline Company, LLC 2002 Phantom Unit Retention Plan ("2002 PURP") The 1999 PURP and the 2002 PURP provide key employees with incentive awards whereby a participant is granted phantom units These phantom units are automatically redeemed for cash based on the vested portion of the fair market value of the phantom units at stated redemption dates The fair market value of each phantom unit is equal to the closing price of a Unit as reported on the New York Stock Exchange on the redemption date

Under the agreement for the phantom units, each participant will vest 10% of the number of phantom units initially granted under his or her award at the end of each of the first four years and will vest the final 60% at the end of the fifth year Each participant is required to

TEPPCO PARTNERS, L P.

Notes To Consolidated Financial Statements—(Continued)

redeem their phantom units as they vest They are also entitled to quarterly cash distributions equal to the product of the number of phantom units outstanding for the participant and the amount of the cash distribution that we paid per Unit to unitholders We accrued compensation expense annually based upon the terms of the 1999 PURP and 2002 PURP discussed above At December 31, 2004, we had an accrued liability balance of $1 6 million for compensation related to the 1999 PURP and 2002 PURP Due to a change of ownership as a result of the sale of our General Partner on February 24, 2005 (see Note 1), all outstanding units under both the 1999 PURP and the 2002 PURP fully vested and were redeemed by participants As such, there were no outstanding units at December 31, 2005 under either the 1999 PURP or the 2002 PURP

2000 Long Term Incentive Plan

Effective January 1, 2000, the General Partner established the Texas Eastern Products Pipeline Company, LLC 2000 Long Term Incentive Plan ("2000 LTIP") to provide key employees incentives to achieve improvements in our financial performance Generally, upon the close of a three-year performance period, if the participant is then still an employee of the General Partner, the participant will receive a cash payment in an amount equal to (1) the applicable performance percentage specified in the award multiplied by (2) the number of phantom units granted under the award multiplied by (3) the average of the closing prices of a Unit over the ten consecutive trading days immediately preceding the last day of the performance period. Generally, a participant's performance percentage is based upon the improvement of our Economic Value Added (as defined below) during a three-year performance period over the Economic Value Added during the three-year period immediately preceding the performance period. If a participant incurs a separation from service during the performance period due to death, disability or retirement (as such terms are defined in the 2000 LTIP), the participant will be entitled to receive a cash payment in an amount equal to the amount computed as described above multiplied by a fraction, the numerator of which is the number of days that have elapsed during the performance period prior to the participant's separation from service and the denominator of which is the number of days in the performance period Due to a change of ownership as a result of the sale of our General Partner on February 24, 2005, all outstanding units under the 2000 LTIP for plan years 2003 and 2004 were fully vested and redeemed by participants As such, there were no outstanding units at December 31, 2005, for awards granted for the plan years ended December 31, 2004 and 2003 At December 31, 2005, phantom units outstanding for awards granted for the plan year ended December 31, 2005, were 23,400

Economic Value Added means our average annual EBITDA for the performance period minus the product of our average asset base and our cost of capital for the performance period. For purposes of the 2000 LTIP for plan years 2000 through 2002, EBITDA means our earnings before net interest expense, depreciation and amortization and our proportional interest in EBITDA of our joint ventures as presented in our consolidated financial statements prepared in accordance with generally accepted accounting principles, except that at his discretion the Chief Executive Officer ("CEO") of the Company may exclude gains or losses from extraordinary, unusual or non-recurring items For the years ended December 31, 2005, 2004 and 2003, EBITDA means, in addition to the above definition of EBITDA, earnings before other income – net Average asset base means the quarterly average, during the performance period, of our gross value of property, plant and equipment, *plus* products and crude oil operating oil supply and the gross value of intangibles and equity investments Our cost of capital is approved by our CEO at the date of award grant

In addition to the payment described above, during the performance period, the General Partner will pay to the participant the amount of cash distributions that we would have paid to our unitholders had the participant been the owner of the number of Units equal to the number of phantom units granted to the participant under this award We accrue compensation expense annually based upon the terms of the 2000 LTIP discussed above. At December 31, 2005 and 2004, we had an accrued liability balance of $0 7 million and $2 4 million, respectively, for compensation related to the 2000 LTIP

2005 Phantom Unit Plan

Effective January 1, 2005, the Company adopted the Texas Eastern Products Pipeline Company, LLC 2005 Phantom Unit Plan ("2005 PURP") to provide key employees incentives to achieve improvements in our financial performance Generally, upon the close of a three-year performance period, if the participant is then still an employee of the General Partner, the participant will receive a cash payment in an amount equal to (1) the grantee's vested percentage multiplied by (2) the number of phantom units granted under the award multiplied by (3) the average of the closing prices of a Unit over the ten consecutive trading days immediately preceding the last day of the performance period Generally, a participant's vested percentage is based upon the improvement of our EBITDA (as defined below) during a three-year performance period over the target EBITDA as defined at the beginning of each year during the three-year performance period EBITDA means our earnings before minority interest, net interest expense, other income – net, income taxes, depreciation and amortization and our proportional interest in EBITDA of our joint ventures as presented in our consolidated financial statements

TEPPCO PARTNERS, L P
Notes To Consolidated Financial Statements—(Continued)

prepared in accordance with generally accepted accounting principles, except that at his discretion, our CEO may exclude gains or losses from extraordinary, unusual or non-recurring items At December 31, 2005, phantom units outstanding for awards granted for the plan year ended December 31, 2005, were 53,600

In addition to the payment described above, during the performance period, the General Partner will pay to the participant the amount of cash distributions that we would have paid to our unitholders had the participant been the owner of the number of Units equal to the number of phantom units granted to the participant under this award We accrue compensation expense annually based upon the terms of the 2005 PURP discussed above At December 31, 2005, we had an accrued liability balance of $0 7 million for compensation related to the 2005 PURP

Note 14. Operating Leases

We use leased assets in several areas of our operations Total rental expense for the years ended December 31, 2005, 2004 and 2003, was $24 0 million, $22 1 million and $18 8 million, respectively The following table sets forth our minimum rental payments under our various operating leases for the years ending December 31 (in thousands):

2006	$19,536
2007	17,391
2008	10,863
2009	7,682
2010	6,645
Thereafter	21,544
	$83,661

Note 15. Employee Benefits

Retirement Plans

The TEPPCO Retirement Cash Balance Plan ("TEPPCO RCBP") was a non-contributory, trustee-administered pension plan In addition, the TEPPCO Supplemental Benefit Plan ("TEPPCO SBP") was a non-contributory, nonqualified, defined benefit retirement plan, in which certain executive officers participated The TEPPCO SBP was established to restore benefit reductions caused by the maximum benefit limitations that apply to qualified plans The benefit formula for all eligible employees was a cash balance formula Under a cash balance formula, a plan participant accumulated a retirement benefit based upon pay credits and current interest credits The pay credits were based on a participant's salary, age and service We used a December 31 measurement date for these plans

On May 27, 2005, the TEPPCO RCBP and the TEPPCO SBP were amended Effective May 31, 2005, participation in the TEPPCO RCBP was frozen, and no new participants were eligible to be covered by the plan after that date Effective December 31, 2005, all plan benefits accrued were frozen, participants will not receive additional pay credits after that date, and all plan participants were 100% vested regardless of their years of service The TEPPCO RCBP plan was terminated effective December 31, 2005, subject to IRS approval of plan termination, and plan participants will have the option to receive their benefits either through a lump sum payment in 2006 or through an annuity For those plan participants who elect to receive an annuity, we will purchase an annuity contract from an insurance company in which the plan participant owns the annuity, absolving us of any future obligation to the participant Participants in the TEPPCO SBP received pay credits through November 30, 2005, and received lump sum benefit payments in December 2005 Both the RCBP and SBP benefit payments are discussed below

In June 2005, we recorded a curtailment charge of $0 1 million in accordance with SFAS No 88, *Employers' Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits*, as a result of the TEPPCO RCBP and TEPPCO SBP amendments As of May 31, 2005, the following assumptions were changed for purposes of determining the net periodic benefit costs for the remainder of 2005: the discount rate, the long-term rate of return on plan assets, and the assumed mortality table The discount rate was decreased from 5 75% to 5 00% to reflect rates of returns on bonds currently available to settle the liability The expected long-term rate of return on plan assets was changed from 8% to 2% due to the movement of plan funds from equity investments into short-term money market funds The mortality table was changed to reflect overall improvements in mortality experienced by the general population The curtailment charge arose due to the accelerated recognition of the unrecognized prior service costs We recorded additional settlement charges of approximately $0 2 million in the fourth quarter of 2005 relating to the TEPPCO SBP We expect to record additional settlement charges of approximately $4 0 million in 2006 relating to the TEPPCO RCBP for any existing unrecognized losses upon the plan termination and final distribution of the assets to the plan participants

TEPPCO PARTNERS, L.P.

Notes To Consolidated Financial Statements—(Continued)

The components of net pension benefits costs for the TEPPCO RCBP and the TEPPCO SBP for the years ended December 31, 2005, 2004 and 2003, were as follows (in thousands):

	Year Ended December 31,		
	2005	2004	2003
Service cost benefit earned during the year	$ 4,393	$ 3,653	$ 3,179
Interest cost on projected benefit obligation	934	719	504
Expected return on plan assets	(671)	(878)	(604)
Amortization of prior service cost	5	7	7
Recognized net actuarial loss	129	57	24
SFAS 88 curtailment charge	50	—	—
SFAS 88 settlement charge	194	—	—
Net pension benefits costs	$ 5,034	$ 3,558	$ 3,110

Other Postretirement Benefits

We provided certain health care and life insurance benefits for retired employees on a contributory and non-contributory basis ("TEPPCO OPB"). Employees became eligible for these benefits if they met certain age and service requirements at retirement, as defined in the plans. We provided a fixed dollar contribution, which did not increase from year to year, towards retired employee medical costs. The retiree paid all health care cost increases due to medical inflation. We used a December 31 measurement date for this plan.

In May 2005, benefits provided to employees under the TEPPCO OPB were changed. Employees eligible for these benefits received them through December 31, 2005, however, effective December 31, 2005, these benefits were terminated. As a result of this change in benefits and in accordance with SFAS No. 106, *Employers' Accounting for Postretirement Benefits Other Than Pensions*, we recorded a curtailment credit of approximately $1.7 million in our accumulated postretirement obligation which reduced our accumulated postretirement obligation to the total of the expected remaining 2005 payments under the TEPPCO OPB. The current employees participating in this plan were transferred to DEFS, who will continue to provide postretirement benefits to these retirees. We recorded a one-time settlement to DEFS in the third quarter of 2005 of $0.4 million for the remaining postretirement benefits.

The components of net postretirement benefits cost for the TEPPCO OPB for the years ended December 31, 2005, 2004 and 2003, were as follows (in thousands):

	Year Ended December 31,		
	2005	2004	2003
Service cost benefit earned during the year	$ 81	$ 165	$ 137
Interest cost on accumulated postretirement benefit obligation	69	153	137
Amortization of prior service cost	53	126	126
Recognized net actuarial loss	4	1	—
Curtailment credit	(1,676)	—	—
Settlement credit	(4)	—	—
Net postretirement benefits costs	$ (1,473)	$ 445	$ 400

Effective June 1, 2005, the payroll functions performed by DEFS for our General Partner were transferred from DEFS to EPCO. For those employees who were receiving certain other postretirement benefits at the time of the acquisition of our General Partner by DFI, DEFS will continue to provide these benefits to those employees. Effective June 1, 2005, EPCO began providing certain other postretirement benefits to those employees who became eligible for the benefits after June 1, 2005, and will charge those benefit related costs to us. As a result of these changes, we recorded a $1.2 million reduction in our other postretirement obligation in June 2005.

We employed a building block approach in determining the long-term rate of return for plan assets. Historical markets were studied and long-term historical relationships between equities and fixed-income were preserved consistent with a widely accepted capital market principle that assets with higher volatility generate a greater return over the long run. Current market factors such as inflation and interest rates were evaluated before long-term capital market assumptions were determined. The long-term portfolio return was established via a building block approach with proper consideration of diversification and rebalancing. Peer data and historical returns were reviewed to check for reasonability and appropriateness.

TEPPCO PARTNERS, L.P.

Notes To Consolidated Financial Statements—(Continued)

The weighted average assumptions used to determine benefit obligations for the retirement plans and other postretirement benefit plans at December 31, 2005 and 2004, were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2005	2004	2005	2004
Discount rate	4.59%	5.75%	5.75%	5.75%
Increase in compensation levels	—	5.00%	—	—

The weighted average assumptions used to determine net periodic benefit cost for the retirement plans and other postretirement benefit plans for the years ended December 31, 2005 and 2004, were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2005	2004	2005	2004
Discount rate(1)	5.75%/5.00%	6.25%	5.75%/5.00%	6.25%
Increase in compensation levels	5.00%	5.00%	—	—
Expected long-term rate of return on plan assets(2)	8.00%/2.00%	8.00%	—	—

(1) Expense was remeasured on May 31, 2005, as a result of TEPPCO RCBP and TEPPCO SBP amendments. The discount rate was decreased from 5.75% to 5% effective June 1, 2005, to reflect rates of returns on bonds currently available to settle the liability.

(2) As a result of TEPPCO RCBP and TEPPCO SBP amendments, the expected return on assets was changed from 8% to 2% due to the movement of plan funds from equity investments into short-term money market funds, effective June 1, 2005.

The following table sets forth our pension and other postretirement benefits changes in benefit obligation, fair value of plan assets and funded status as of December 31, 2005 and 2004 (in thousands):

	Pension Benefits		Other Postretirement Benefits	
	2005	2004	2005	2004
Change in benefit obligation				
Benefit obligation at beginning of year	$ 15,940	$ 11,256	$ 2,964	$ 2,467
Service cost	4,393	3,653	81	165
Interest cost	934	719	70	153
Actuarial loss	2,740	572	76	205
Retiree contributions	—	—	64	60
Benefits paid	(910)	(260)	(80)	(86)
Impact of curtailment	(986)	—	(3,575)	—
Settlement	—	—	400	—
Benefit obligation at end of year	$ 22,111	$ 15,940	$ —	$ 2,964
Change in plan assets				
Fair value of plan assets at beginning of year	$ 14,969	$ 10,921	$ —	$ —
Actual return on plan assets	20	808	—	—
Retiree contributions	—	—	64	60
Employer contributions	9,025	3,500	16	26
Benefits paid	(910)	(260)	(80)	(86)
Fair value of plan assets at end of year	$ 23,104	$ 14,969	$ —	$ —
Reconciliation of funded status				
Funded status	$ 994	$ (971)	$ —	$ (2,964)
Unrecognized prior service cost	—	33	—	1,003
Unrecognized actuarial loss	4,067	2,006	—	472
Net amount recognized	$ 5,061	$ 1,068	$ —	$ (1,489)

We estimate the following benefit payments, which reflect expected future service, as appropriate, will be paid (in thousands):

	Pension Benefits	Other Postretirement Benefits
2006	$ 22,360	$ —

TEPPCO PARTNERS, L P
Notes To Consolidated Financial Statements—(Continued)

Plan Assets

We employed a total return investment approach whereby a mix of equities and fixed income investments were used to maximize the long-term return of plan assets for a prudent level of risk Risk tolerance was established through careful consideration of plan liabilities, plan funded status and corporate financial condition The investment portfolio contained a diversified blend of equity and fixed-income investments Furthermore, equity investments were diversified across U S and non-U S stocks, both growth and value equity style, and small, mid and large capitalizations Investment risk and return parameters were reviewed and evaluated periodically to ensure compliance with stated investment objectives and guidelines This comprehensive review incorporated investment portfolio performance, annual liability measurements and periodic asset/liability studies

The following table sets forth the weighted average asset allocations for the retirement plans and other postretirement benefit plans as of December 31, 2005 and 2004, by asset category (in thousands):

	December 31,	
Asset Category	2005	2004
Equity securities	—	63%
Debt securities	—	35%
Other (money market and cash)	100%	2%
Total	100%	100%

We do not expect to make further contributions to our retirement plans and other postretirement benefit plans in 2006

Other Plans

DEFS also sponsored an employee savings plan, which covered substantially all employees Effective February 24, 2005, in conjunction with the change in ownership of our General Partner, our participation in this plan ended Plan contributions on behalf of the Company of $0.9 million, $3 5 million and $3 2 million were recognized for the period January 1, 2005 through February 23, 2005, and during the years ended December 31, 2004 and 2003, respectively

Note 16. Commitments and Contingencies

Litigation

In the fall of 1999 and on December 1, 2000, the General Partner and the Partnership were named as defendants in two separate lawsuits in Jackson County Circuit Court, Jackson County, Indiana, styled *Ryan E. McCleery and Marcia S. McCleery, et al v. Texas Eastern Corporation, et al.* (including the General Partner and Partnership) and *Gilbert Richards and Jean Richards v. Texas Eastern Corporation, et al.* (including the General Partner and Partnership) In both cases, the plaintiffs contend, among other things, that we and other defendants stored and disposed of toxic and hazardous substances and hazardous wastes in a manner that caused the materials to be released into the air, soil and water They further contend that the release caused damages to the plaintiffs In their complaints, the plaintiffs allege strict liability for both personal injury and property damage together with gross negligence, continuing nuisance, trespass, criminal mischief and loss of consortium The plaintiffs are seeking compensatory, punitive and treble damages On January 27, 2005, we entered into Release and Settlement Agreements with the McCleery plaintiffs and the Richards plaintiffs dismissing all of these plaintiffs' claims on terms that did not have a material adverse effect on our financial position, results of operations or cash flows Although we did not settle with all plaintiffs and we therefore remain named parties in the *Ryan E. McCleery and Marcia S. McCleery, et al v. Texas Eastern Corporation, et al* action, a co-defendant has agreed to indemnify us for all remaining claims asserted against us Consequently, we do not believe that the outcome of these remaining claims will have a material adverse effect on our financial position, results of operations or cash flows

On December 21, 2001, TE Products was named as a defendant in a lawsuit in the 10th Judicial District, Natchitoches Parish, Louisiana, styled *Rebecca L. Grisham et al. v. TE Products Pipeline Company, Limited Partnership* In this case, the plaintiffs contend that our pipeline, which crosses the plaintiffs' property, leaked toxic products onto their property and, consequently caused damages to them We have filed an answer to the plaintiffs' petition denying the allegations, and we are defending ourselves vigorously against the lawsuit The plaintiffs have not stipulated the amount of damages they are seeking in the suit; however, this case is covered by insurance We do not believe that the outcome of this lawsuit will have a material adverse effect on our financial position, results of operations or cash flows

On April 2, 2003, Centennial was served with a petition in a matter styled *Adams, et al. v. Centennial Pipeline Company LLC, et al.* This matter involves approximately 2,000 plaintiffs who allege that over 200 defendants, including Centennial, generated, transported, and/or disposed of hazardous and toxic waste at two sites in Bayou Sorrell, Louisiana, an underground injection well and a landfill The

Table of Contents

plaintiffs allege personal injuries, allergies, birth defects, cancer and death The underground injection well has been in operation since May 1976 Based upon current information, Centennial appears to be a *de minimis* contributor, having used the disposal site during the two month time period of December 2001 to January 2002 Marathon has been handling this matter for Centennial under its operating agreement with Centennial TE Products has a 50% ownership interest in Centennial On November 30, 2004, the court approved a class settlement. The time period for parties to appeal this settlement expired in March 2005, and the class settlement became final The terms of the settlement did not have a material adverse effect on our financial position, results of operations or cash flows.

In May 2003, the General Partner was named as a defendant in a lawsuit styled *John R. James, et al. v. J Graves Insulation Company, et al.* as filed in the first Judicial District Court, Caddo Parish, Louisiana There are numerous plaintiffs identified in the action that are alleged to have suffered damages as a result of alleged exposure to asbestos-containing products and materials. According to the petition and as a result of a preliminary investigation, the General Partner believes that the only claim asserted against it results from one individual for the period from July 1971 through June 1972, who is alleged to have worked on a facility owned by the General Partner's predecessor This period represents a small portion of the total alleged exposure period from January 1964 through December 2001 for this individual. The individual's claims involve numerous employers and alleged job sites The General Partner has been unable to confirm involvement by the General Partner or its predecessors with the alleged location, and it is uncertain at this time whether this case is covered by insurance Discovery is planned, and the General Partner intends to defend itself vigorously against this lawsuit The plaintiffs have not stipulated the amount of damages that they are seeking in this suit We are obligated to reimburse the General Partner for any costs it incurs related to this lawsuit. We cannot estimate the loss, if any, associated with this pending lawsuit. We do not believe that the outcome of this lawsuit will have a material adverse effect on our financial position, results of operations or cash flows

On August 5, 2005, we were named as a third-party defendant in a matter styled *ConocoPhillips, et al. v. BP Amoco Seaway Products Pipeline Company* as filed in the 55th Judicial District of Harris County, Texas ConocoPhillips alleges a right to indemnity from BP Amoco Seaway Products Pipeline Company ("BP Amoco") for tax liability incurred by ConocoPhillips as a result of the reverse merger of Seaway Pipeline Company (the "Original Seaway Partnership") The reverse merger of the Original Seaway Partnership was undertaken in preparation for our purchase of ARCO Pipe Line Company pursuant to the Amended and Restated Purchase Agreement (the "Purchase Agreement") dated May 10, 2000, between us and Atlantic Richfield Company BP Amoco has claimed a right to indemnity from us under the Purchase Agreement should BP Amoco have any indemnity liability to ConocoPhillips ConocoPhillips alleges the income tax liability to be approximately $4 0 million On January 20, 2006, we entered into a settlement agreement with BP Amoco dismissing and resolving all of BP Amoco's claims The terms of the settlement did not have a material adverse effect on our financial position, results of operations or cash flows

In 1991, we were named as a defendant in a matter styled *Jimmy R. Green, et al. v. Cities Service Refinery, et al.* as filed in the 26th Judicial District Court of Bossier Parish, Louisiana The plaintiffs in this matter reside or formerly resided on land that was once the site of a refinery owned by one of our co-defendants The former refinery is located near our Bossier City facility Plaintiffs have claimed personal injuries and property damage arising from alleged contamination of the refinery property The plaintiffs have recently pursued certification as a class and have significantly increased their demand to approximately $175 0 million This revised demand includes amounts for environmental restoration not previously claimed by the plaintiffs We have never owned any interest in the refinery property made the basis of this action, and we do not believe that we contributed to any alleged contamination of this property While we cannot predict the ultimate outcome, we do not believe that the outcome of this lawsuit will have a material adverse effect on our financial position, results of operations or cash flows

In addition to the litigation discussed above, we have been, in the ordinary course of business, a defendant in various lawsuits and a party to various other legal proceedings, some of which are covered in whole or in part by insurance We believe that the outcome of these lawsuits and other proceedings will not individually or in the aggregate have a future material adverse effect on our consolidated financial position, results of operations or cash flows

Regulatory Matters

Our operations are subject to federal, state and local laws and regulations governing the discharge of materials into the environment and various safety matters Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, imposition of injunctions delaying or prohibiting certain activities and the need to perform investigatory and remedial activities We believe our operations have been and are in material compliance with applicable environmental and safety laws and regulations, and that compliance with existing environmental laws and regulations are not expected to have a material adverse effect on our competitive position, financial positions, results of operations or cash flows. However, risks of significant costs and liabilities are inherent in pipeline operations, and we cannot assure that significant costs and liabilities will not be incurred Moreover, it is possible that other developments, such as increasingly strict environmental and safety laws and regulations and enforcement policies thereunder, and claims

TEPPCO PARTNERS, L P

Notes To Consolidated Financial Statements—(Continued)

for damages to property or persons resulting from our operations, could result in substantial costs and liabilities to us At December 31, 2005 and 2004, we have an accrued liability of $2 4 million and $5 0 million, respectively, related to sites requiring environmental remediation activities

On March 26, 2004, a decision in *ARCO Products Co., et al v. SFPP*, Docket OR96-2-000, was issued by the FERC, which made several significant determinations with respect to finding "changed circumstances" under the Energy Policy Act of 1992 ("EP Act") The decision largely clarifies, but does not fully quantify, the standard required for a complainant to demonstrate that an oil pipeline's rates are no longer subject to the rate protection of the EP Act by demonstrating that a substantial change in circumstances has occurred since 1992 with respect to the basis of the rates being challenged In the decision, the FERC found that a limited number of rate elements will significantly affect the economic basis for a pipeline company's rates The elements identified in the decision are volume changes, allowed total return and total cost-of-service (including major cost elements such as rate base, tax rates and tax allowances, among others) The FERC did reject, however, the use of changes in tax rates and income tax allowances as stand-alone factors Judicial review of that decision, which has been sought by a number of parties to the case, is currently pending before the U S Court of Appeals for the District of Columbia Circuit We have not yet determined the impact, if any, that the decision, if it is ultimately upheld, would have on our rates if they were reviewed under the criteria of this decision

On July 20, 2004, the District of Columbia Circuit issued an opinion in *BP West Coast Products LLC v. FERC* In reviewing a series of orders involving SFPP, L P , the court held among other things that the FERC had not adequately justified its policy of providing an oil pipeline limited partnership with an income tax allowance equal to the proportion of its income attributable to partnership interests owned by corporate partners. Under the FERC's initial ruling, SFPP, L.P. was permitted an income tax allowance on its cost-of-service filing for the percentage of its net operating (pre-tax) income attributable to partnership units held by corporations, and was denied an income tax allowance equal to the percentage attributable to partnership units held by non-corporate partners The court remanded the case back to the FERC for further review As a result of the court's remand, on May 4, 2005, the FERC issued its Policy Statement on Income Tax Allowances, which permits regulated partnerships, limited liability companies and other pass-through entities an income tax allowance on their income attributable to any owner that has an actual or potential income tax liability on that income, regardless whether the owner is an individual or corporation If there is more than one level of pass-through entities, the regulated company income must be traced to where the ultimate tax liability lies The Policy Statement is to be applied in individual cases, and the regulated entity bears the burden of proof to establish the tax status of its owners On December 16, 2005, the FERC issued the first of those decisions, in an order involving SFPP (the "SFPP Order") The SFPP Order confirmed that an MLP is entitled to a tax allowance with respect to partnership income for which there is an "actual or potential income tax liability" and determined that a unitholder that is required to file a Form 1040 or Form 1120 tax return that includes partnership income or loss is presumed to have an actual or potential income tax liability sufficient to support a tax allowance on that partnership income The FERC also established certain other presumptions, including that corporate unitholders are presumed to be taxed at the maximum corporate tax rate of 35% while individual unitholders (and certain other types of unitholders taxed like individuals) are presumed to be taxed at a 28% tax rate The SFPP Order remains subject to further administrative proceedings (including compliance filings by SFPP and possible rehearing requests), as well as potential judicial review The ultimate outcome of the FERC's inquiry on income tax allowance should not affect our current rates and rate structure because our rates are not based on cost-of-service methodology However, the outcome of the income tax allowance would become relevant to us should we (i) elect in the future to use cost-of-service to support our rates, or (ii) be required to use such methodology to defend our indexed rates

In 1994, the Louisiana Department of Environmental Quality ("LDEQ") issued a compliance order for environmental contamination at our Arcadia, Louisiana, facility In 1999, our Arcadia facility and adjacent terminals were directed by the Remediation Services Division of the LDEQ to pursue remediation of this contamination Effective March 2004, we executed an access agreement with an adjacent industrial landowner who is located upgradient of the Arcadia facility This agreement enables the landowner to proceed with remediation activities at our Arcadia facility for which it has accepted shared responsibility At December 31, 2005, we have an accrued liability of $0 2 million for remediation costs at our Arcadia facility We do not expect that the completion of the remediation program proposed to the LDEQ will have a future material adverse effect on our financial position, results of operations or cash flows

On March 17, 2003, we experienced a release of 511 barrels of jet fuel from a storage tank at our Blue Island terminal located in Cook County, Illinois As a result of the release, we have entered into an Agreed Order with the State of Illinois, which required us to conduct an environmental investigation At this time, we have complied with the terms of the Agreed Order, and the results of the environmental investigation indicated there were no soil or groundwater impacts from the release On August 30, 2005, a final settlement was reached with the State of Illinois The settlement included the payment of a civil penalty of $0 1 million and the requirement that we make certain modifications to the equipment of the facility, none of which are expected to have a material adverse effect on our financial position, results of operations or cash flows

TEPPCO PARTNERS, L.P.
Notes To Consolidated Financial Statements—(Continued)

On July 22, 2004, we experienced a release of approximately 12 barrels of jet fuel from a sump at our Lebanon, Ohio, terminal The released jet fuel was contained within a storm water retention pond located on the terminal property. Six migratory waterfowl were affected by the jet fuel and were subsequently euthanized by or at the request of the United States Fish and Wildlife Service ("USFWS") On October 1, 2004, the USFWS served us with a Notice of Violation, alleging that we violated 16 USC 703 of the Migratory Bird Treaty Act for the "take[ing] of migratory birds by illegal methods " On February 7, 2005, we entered into a Memorandum of Understanding with the USFWS, settling all aspects of this matter The terms of this settlement did not have a material effect on our financial position, results of operations or cash flows

On July 27, 2004, we received notice from the United States Department of Justice ("DOJ") of its intent to seek a civil penalty against us related to our November 21, 2001, release of approximately 2,575 barrels of jet fuel from our 14-inch diameter pipeline located in Orange County, Texas. The DOJ, at the request of the Environmental Protection Agency, is seeking a civil penalty against us for alleged violations of the Clean Water Act ("CWA") arising out of this release We are in discussions with the DOJ regarding this matter and have responded to its request for additional information. The maximum statutory penalty proposed by the DOJ for this alleged violation of the CWA is $2 1 million. We do not expect any civil penalty to have a material adverse effect on our financial position, results of operations or cash flows

On September 18, 2005, a propane release and fire occurred at our Todhunter facility, near Middletown, Ohio The incident resulted in the death of one of our employees There were no other injuries. On or about February 22, 2006, we received verbal notification from a representative of the Occupational Safety and Health Administration that they intend to serve us with a ~~citation arising out of this incident. At this time, we have not received any citation, and we cannot predict with certainty the amount of any fine or penalty associated with any such citation;~~ however, we do not expect any fine or penalty to have a material adverse effect on our financial position, results of operations or cash flows

Rates of interstate petroleum products and crude oil pipeline companies, like us, are currently regulated by the FERC primarily through an index methodology, which allows a pipeline to change its rates based on the change from year to year in the Producer Price Index for finished goods ("PPI Index") Effective as of February 24, 2003, FERC Order on Remand modified the PPI Index from PPI – 1% to PPI On April 22, 2003, several shippers filed a petition in the United States Court of Appeals for the District of Columbia Circuit (the "Court"), *Flying J. Inc., Lion Oil Company, Sinclair Oil Corporation and Tesoro Refining and Marketing Company vs. Federal Energy Regulatory Commission*; Docket No 03-1107, seeking a review of whether the FERC's adoption of the PPI Index was reasonable and supported by the evidence On April 9, 2004, the Court handed down a decision denying the shippers' petition for review, stating the shippers failed to establish that any of the FERC's methodological choices (or combination of choices) were both erroneous and harmful

As an alternative to using the PPI Index, interstate petroleum products and crude oil pipeline companies may elect to support rate filings by using a cost-of-service methodology, competitive market showings ("Market- Based Rates") or agreements between shippers and petroleum products and crude oil pipeline companies that the rate is acceptable.

Other

Centennial entered into credit facilities totaling $150 0 million, and as of December 31, 2005, $150 0 million was outstanding under those credit facilities TE Products and Marathon have each guaranteed one-half of the repayment of Centennial's outstanding debt balance (plus interest) under a long-term credit agreement, which expires in 2024, and a short-term credit agreement, which expires in 2007 The guarantees arose in order for Centennial to obtain adequate financing, and the proceeds of the credit agreements were used to fund construction and conversion costs of its pipeline system Prior to the expiration of the long-term credit agreement, TE Products could be relinquished from responsibility under the guarantee should Centennial meet certain financial tests If Centennial defaults on its outstanding balance, the estimated maximum potential amount of future payments for TE Products and Marathon is $75 0 million each at December 31, 2005

TE Products, Marathon and Centennial have entered into a limited cash call agreement, which allows each member to contribute cash in lieu of Centennial procuring separate insurance in the event of a third-party liability arising from a catastrophic event There is an indefinite term for the agreement and each member is to contribute cash in proportion to its ownership interest, up to a maximum of $50 0 million each. As a result of the catastrophic event guarantee, TE Products has recorded a $4 6 million obligation, which represents the present value of the estimated amount that we would have to pay under the guarantee If a catastrophic event were to occur and we were required to contribute cash to Centennial, contributions exceeding our deductible might be covered by our insurance

One of our subsidiaries, TCO, has entered into master equipment lease agreements with finance companies for the use of various equipment. We have guaranteed the full and timely payment and performance of TCO's obligations under the agreements Generally, events of default would trigger our performance under the guarantee The maximum potential amount of future payments under the

TEPPCO PARTNERS, L.P.

Notes To Consolidated Financial Statements—(Continued)

guarantee is not estimable, but would include base rental payments for both current and future equipment, stipulated loss payments in the event any equipment is stolen, damaged, or destroyed and any future indemnity payments. We carry insurance coverage that may offset any payments required under the guarantees.

On February 24, 2005, the General Partner was acquired from DEFS by DFI. The General Partner owns a 2% general partner interest in us and is the general partner of the Partnership. On March 11, 2005, the Bureau of Competition of the Federal Trade Commission ("FTC") delivered written notice to DFI's legal advisor that it was conducting a non-public investigation to determine whether DFI's acquisition of the General Partner may substantially lessen competition. The General Partner is cooperating fully with this investigation.

Substantially all of the petroleum products that we transport and store are owned by our customers. At December 31, 2005, TCTM and TE Products had approximately 4.0 million barrels and 22.5 million barrels, respectively, of products in their custody that was owned by customers. We are obligated for the transportation, storage and delivery of such products on behalf of our customers. We maintain insurance adequate to cover product losses through circumstances beyond our control.

We carry insurance coverage consistent with the exposures associated with the nature and scope of our operations. Our current insurance coverage includes (1) commercial general liability insurance for liabilities to third parties for bodily injury and property damage resulting from our operations; (2) workers' compensation coverage to required statutory limits; (3) automobile liability insurance for all owned, non-owned and hired vehicles covering liabilities to third parties for bodily injury and property damage, and (4) property insurance covering the replacement value of all real and personal property damage, including damages arising from earthquake, flood damage and business interruption/extra expense. For select assets, we also carry pollution liability insurance that provides coverage for historical and gradual pollution events. All coverages are subject to certain deductibles, limits or sub-limits and policy terms and conditions.

We also maintain excess liability insurance coverage above the established primary limits for commercial general liability and automobile liability insurance. Limits, terms, conditions and deductibles are commensurate with the nature and scope of our operations. The cost of our general insurance coverages has increased over the past year reflecting the changing conditions of the insurance markets. These insurance policies, except for the pollution liability policies, are through EPCO (see Note 7).

Note 17. Segment Information

We have three reporting segments:

- Our Downstream Segment, which is engaged in the transportation and storage of refined products, LPGs and petrochemicals;
- Our Upstream Segment, which is engaged in the gathering, transportation, marketing and storage of crude oil and distribution of lubrication oils and specialty chemicals; and
- Our Midstream Segment, which is engaged in the gathering of natural gas, fractionation of NGLs and transportation of NGLs.

The amounts indicated below as "Partnership and Other" relate primarily to intersegment eliminations and assets that we hold that have not been allocated to any of our reporting segments.

Our Downstream Segment revenues are earned from transportation and storage of refined products and LPGs, intrastate transportation of petrochemicals, sale of product inventory and other ancillary services. The two largest operating expense items of the Downstream Segment are labor and electric power. We generally realize higher revenues during the first and fourth quarters of each year since our operations are somewhat seasonal. Refined products volumes are generally higher during the second and third quarters because of greater demand for gasolines during the spring and summer driving seasons. LPGs volumes are generally higher from November through March due to higher demand for propane, a major fuel for residential heating. Our Downstream Segment also includes the results of operations of the northern portion of the Dean Pipeline, which transports, refinery grade propylene from Mont Belvieu to Point Comfort, Texas. Our Downstream Segment also includes our equity investments in Centennial and MB Storage (see Note 6).

Our Upstream Segment revenues are earned from gathering, transportation, marketing and storage of crude oil and distribution of lubrication oils and specialty chemicals, principally in Oklahoma, Texas, New Mexico and the Rocky Mountain region. Marketing operations consist primarily of aggregating purchased crude oil along our pipeline systems, or from third party pipeline systems, and arranging the necessary transportation logistics for the ultimate sale of the crude oil to local refineries, marketers or other end users. Our Upstream Segment also includes our equity investment in Seaway. Seaway consists of large diameter pipelines that transport crude oil from Seaway's marine terminals on the U.S. Gulf Coast to Cushing, Oklahoma, a crude oil distribution point for the central United States, and to refineries in the Texas City and Houston areas.

Our Midstream Segment revenues are earned from the fractionation of NGLs in Colorado, transportation of NGLs from two trunkline NGL pipelines in South Texas, two NGL pipelines in East Texas and a pipeline system (Chaparral) from West Texas and New Mexico to Mont Belvieu; the gathering of natural gas in the Green River Basin in southwestern Wyoming, through Jonah, and the gathering of CBM

TEPPCO PARTNERS, L.P.

Notes To Consolidated Financial Statements—(Continued)

and conventional natural gas in the San Juan Basin in New Mexico and Colorado, through Val Verde. On March 31, 2006, we sold our ownership interest in the Jonah Pioneer silica gel natural gas processing plant located near Opal, Wyoming to an affiliate of Enterprise for $38.0 million in cash (see Note 5 in the Notes to the Consolidated Financial Statements). Operating results of the Pioneer plant for the years ended December 31, 2005 and 2004 are shown as discontinued operations.

The tables below include financial information by reporting segment for the years ended December 31, 2005, 2004 and 2003 (in thousands):

	Year Ended December 31, 2005					
	Downstream Segment	Upstream Segment	Midstream Segment	Segments Total	Partnership and Other	Consolidated
Sales of petroleum products	$ —	$ 8,062,131	$ —	$ 8,062,131	$ (323)	$ 8,061,808
Operating revenues	287,191	48,108	211,171	546,470	(3,244)	543,226
Purchases of petroleum products	—	7,989,682	—	7,989,682	(3,244)	7,986,438
Operating expenses, including power	159,784	70,340	58,701	288,825	(323)	288,502
Depreciation and amortization expense	39,403	17,161	54,165	110,729	—	110,729
Gains on sales of assets	(139)	(118)	(411)	(668)		(668)
Operating income	88,143	33,174	98,716	220,033	—	220,033
Equity earnings (losses)	(2,984)	23,078	—	20,094	—	20,094
Other income, net	755	156	224	1,135	—	1,135
Earnings before interest from continuing operations	85,914	56,408	98,940	241,262	—	241,262
Discontinued operations	—	—	3,150	3,150	—	3,150
Earnings before interest	$ 85,914	$ 56,408	$ 102,090	$ 244,412	$ —	$ 244,412

	Year Ended December 31, 2004					
	Downstream Segment (as restated)	Upstream Segment (as restated)	Midstream Segment	Segments Total (as restated)	Partnership and Other	Consolidated (as restated)
Sales of petroleum products	$ —	$ 5,426,832	$ —	$ 5,426,832	$ —	$ 5,426,832
Operating revenues	279,400	49,163	195,902	524,465	(3,207)	521,258
Purchases of petroleum products	—	5,370,234	—	5,370,234	(3,207)	5,367,027
Operating expenses, including power	165,528	60,893	58,967	285,388	—	285,388
Depreciation and amortization expense	43,135	13,130	56,019	112,284	—	112,284
Gains on sales of assets	(526)	(527)		(1,053)	—	(1,053)
Operating income	71,263	32,265	80,916	184,444	—	184,444
Equity earnings (losses)	(6,544)	28,692	—	22,148	—	22,148
Other income, net	787	406	127	1,320	—	1,320
Earnings before interest from continuing operations	65,506	61,363	81,043	207,912	—	207,912
Discontinued operations	—	—	2,689	2,689	—	2,689
Earnings before interest	$ 65,506	$ 61,363	$ 83,732	$ 210,601	$ —	$ 210,601

TEPPCO PARTNERS, L P
Notes To Consolidated Financial Statements—(Continued)

	Year Ended December 31, 2003					
	Downstream Segment (as restated)	Upstream Segment (as restated)	Midstream Segment	Segments Total (as restated)	Partnership and Other	Consolidated (as restated)
Sales of petroleum products	$ —	$ 3,766,651	$ —	$ 3,766,651	$ —	$ 3,766,651
Operating revenues	266,427	39,564	185,105	491,096	(1,915)	489,181
Purchases of petroleum products	—	3,713,122	—	3,713,122	(1,915)	3,711,207
Operating expenses, including power	151,103	57,314	47,020	255,437	—	255,437
Depreciation and amortization expense	31,620	11,311	57,797	100,728	—	100,728
Gain on sale of assets	—	(3,948)		(3,948)	—	(3,948)
Operating income	83,704	28,416	80,288	192,408	—	192,408
Equity earnings (losses)	(7,384)	20,258	—	12,874	—	12,874
Other income, net	226	306	289	821	(73)	748
Earnings before interest	$ 76,546	$ 48,980	$ 80,577	$ 206,103	$ (73)	$ 206,030

The following table provides the total assets, capital expenditures and significant non-cash investing activities for each segment as of and for the years ended December 31, 2005, 2004 and 2003 (in thousands):

	Downstream Segment	Upstream Segment	Midstream Segment	Segments Total	Partnership and Other	Consolidated
December 31, 2005:						
Total assets	$ 1,056,217	$ 1,353,492	$ 1,280,548	$ 3,690,257	$ (9,719)	$ 3,680,538
Capital expenditures	58,609	40,954	119,837	219,400	1,153	220,553
Non-cash investing activities	1,429	—	—	1,429	—	1,429
December 31, 2004 (as restated):						
Total assets	$ 959,042	$ 1,069,007	$ 1,184,184	$ 3,212,233	$ (25,949)	$ 3,186,284
Capital expenditures	80,930	37,448	37,677	156,055	694	156,749
Capital expenditures for discontinued operations	—	—	7,398	7,398	—	7,398
December 31, 2003 (as restated):						
Total assets	$ 911,184	$ 833,723	$ 1,194,844	$ 2,939,751	$ (5,271)	$ 2,934,480
Capital expenditures	59,061	13,427	54,072	126,560	147	126,707
Capital expenditures for discontinued operations	—	—	13,810	13,810	—	13,810
Non-cash investing activities	61,042	—	—	61,042	—	61,042

The following table reconciles the segments total earnings before interest to consolidated net income for the three years ended December 31, 2005, 2004 and 2003 (in thousands):

	Years Ended December 31,		
	2005	2004 (as restated)	2003 (as restated)
Earnings before interest	$ 244,412	$ 210,601	$ 206,030
Interest expense—net	(81,861)	(72,053)	(84,250)
Net income	$ 162,551	$ 138,548	$ 121,780

Note 18. Comprehensive Income

SFAS No 130, *Reporting Comprehensive Income* requires certain items such as foreign currency translation adjustments, minimum pension liability adjustments and unrealized gains and losses on certain investments to be reported in a financial statement As of and for the year ended December 31, 2005, the components of comprehensive income were due to crude oil hedges The crude oil hedges mature in December 2006 While the crude oil hedges are in effect, changes in the fair values of the crude oil hedges, to the extent the hedges are effective, are recognized in other comprehensive income until they are recognized in net income in future periods As of and for the year ended December 31, 2004, the components of comprehensive income were due to the interest rate swap related to our variable rate revolving credit facility, which was designated as a cash flow hedge The interest rate swap matured in April 2004 While the

TEPPCO PARTNERS, L P

Notes To Consolidated Financial Statements—(Continued)

interest rate swap was in effect, changes in the fair value of the cash flow hedge, to the extent the hedge was effective, were recognized in other comprehensive income until the hedge interest costs were recognized in net income

The accumulated balance of other comprehensive income related to our cash flow hedges is as follows (in thousands):

Balance at December 31, 2002 (as restated)	$	(20,055)
Reclassification due to discontinued portion of cash flow hedge		989
Transferred to earnings		14,417
Change in fair value of cash flow hedge		1,747
Balance at December 31, 2003 (as restated)	$	(2,902)
Transferred to earnings		2,939
Change in fair value of cash flow hedge		(37)
Balance at December 31, 2004 (as restated)	$	—
Changes in fair values of crude oil cash flow hedges		11
Balance at December 31, 2005	$	11

Note 19. Supplemental Condensed Consolidating Financial Information

Our significant operating subsidiaries, TE Products Pipeline Company, Limited Partnership, TCTM, L P , TEPPCO Midstream Companies, L P , Jonah Gas Gathering Company and Val Verde Gas Gathering Company, L P , have issued unconditional guarantees of our debt securities The guarantees are full, unconditional, and joint and several. TE Products Pipeline Company, Limited Partnership, TCTM, L P , TEPPCO Midstream Companies, L P , Jonah Gas Gathering Company and Val Verde Gas Gathering Company, L P are collectively referred to as the "Guarantor Subsidiaries "

The following supplemental condensed consolidating financial information reflects our separate accounts, the combined accounts of the Guarantor Subsidiaries, the combined accounts of our other non-guarantor subsidiaries, the combined consolidating adjustments and eliminations and our consolidated accounts for the dates and periods indicated For purposes of the following consolidating information, our investments in our subsidiaries and the Guarantor Subsidiaries' investments in their subsidiaries are accounted for under the equity method of accounting

	December 31, 2005				
	TEPPCO Partners, L.P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
			(in thousands)		
Assets					
Current assets	$ 40,977	$ 107,692	$ 789,486	$ (39,026)	$ 899,129
Property, plant and equipment—net	—	1,335,724	624,344	—	1,960,068
Equity investments	1,201,388	461,741	202,343	(1,505,816)	359,656
Intercompany notes receivable	1,134,093	—	—	(1,134,093)	—
Intangible assets	—	345,005	31,903	—	376,908
Other assets	5,532	22,170	57,075	—	84,777
Total assets	$ 2,381,990	$ 2,272,332	$ 1,705,151	$ (2,678,935)	$ 3,680,538
Liabilities and partners' capital					
Current liabilities	$ 43,236	$ 140,743	$ 793,683	$ (40,451)	$ 937,211
Long-term debt	1,135,973	389,048	—	—	1,525,021
Intercompany notes payable	—	635,263	498,832	(1,134,095)	—
Other long term liabilities	1,422	14,564	950	—	16,936
Total partners' capital	1,201,359	1,092,714	411,686	(1,504,389)	1,201,370
Total liabilities and partners' capital	$ 2,381,990	$ 2,272,332	$ 1,705,151	$ (2,678,935)	$ 3,680,538

TEPPCO PARTNERS, L.P.

Notes To Consolidated Financial Statements—(Continued)

	December 31, 2004 (as restated)				
	TEPPCO Partners, L.P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
			(in thousands)		
Assets					
Current assets	$ 44,125	$ 85,992	$ 576,365	$ (62,928)	$ 643,554
Property, plant and equipment—net	—	1,211,312	492,390	—	1,703,702
Equity investments	1,011,131	420,343	202,326	(1,270,493)	363,307
Intercompany notes receivable	1,084,034	—	—	(1,084,034)	—
Intangible assets	—	372,621	34,737	—	407,358
Other assets	5,980	22,183	40,200	—	68,363
Total assets	$ 2,145,270	$ 2,112,451	$ 1,346,018	$ (2,417,455)	$ 3,186,284
Liabilities and partners' capital					
Current liabilities	$ 45,255	$ 142,513	$ 556,474	$ (62,930)	$ 681,312
Long-term debt	1,086,909	393,317	—	—	1,480,226
Intercompany notes payable	—	676,993	407,040	(1,084,033)	—
Other long term liabilities	2,003	9,980	1,660	—	13,643
Total partners' capital	1,011,103	889,648	380,844	(1,270,492)	1,011,103
Total liabilities and partners' capital	$ 2,145,270	$ 2,112,451	$ 1,346,018	$ (2,417,455)	$ 3,186,284

	Year Ended December 31, 2005				
	TEPPCO Partners, L.P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
			(in thousands)		
Operating revenues	$ —	$ 439,944	$ 8,168,657	$ (3,567)	$ 8,605,034
Costs and expenses	—	285,072	8,104,164	(3,567)	8,385,669
Gains on sales of assets	—	(551)	(117)	—	(668)
Operating income	—	155,423	64,610	—	220,033
Interest expense—net	—	(54,011)	(27,850)	—	(81,861)
Equity earnings	162,551	57,088	23,078	(222,623)	20,094
Other income—net	—	901	234	—	1,135
Income from continuing operations	162,551	159,401	60,072	(222,623)	159,401
Discontinued operations	—	3,150	—	—	3,150
Net income	$ 162,551	$ 162,551	$ 60,072	$ (222,623)	$ 162,551

	Year Ended December 31, 2004 (as restated)				
	TEPPCO Partners, L.P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
			(in thousands)		
Operating revenues	$ —	$ 420,060	$ 5,531,237	$ (3,207)	$ 5,948,090
Costs and expenses	—	294,155	5,473,751	(3,207)	5,764,699
Gains on sales of assets	—	(526)	(527)	—	(1,053)
Operating income	—	126,431	58,013	—	184,444
Interest expense—net	—	(48,902)	(23,151)	—	(72,053)
Equity earnings	138,548	57,454	28,692	(202,546)	22,148
Other income—net	—	876	444	—	1,320
Income from continuing operations	138,548	135,859	63,998	(202,546)	135,859
Discontinued operations	—	2,689	—	—	2,689
Net income	$ 138,548	$ 138,548	$ 63,998	$ (202,546)	$ 138,548

TEPPCO PARTNERS, L.P.

Notes To Consolidated Financial Statements—(Continued)

	Year Ended December 31, 2003 (as restated)				
	TEPPCO Partners, L.P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
			(in thousands)		
Operating revenues	$ —	$ 399,504	$ 3,858,243	$ (1,915)	$ 4,255,832
Costs and expenses	—	262,971	3,806,316	(1,915)	4,067,372
Gain on sale of assets	—	—	(3,948)	—	(3,948)
Operating income	—	136,533	55,875	—	192,408
Interest expense—net	—	(52,903)	(31,420)	73	(84,250)
Equity earnings	121,780	37,689	20,258	(166,853)	12,874
Other income—net	—	461	360	(73)	748
Net income	$ 121,780	$ 121,780	$ 45,073	$ (166,853)	$ 121,780

	Year Ended December 31, 2005				
	TEPPCO Partners, L.P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
			(in thousands)		
Cash flows from continuing operating activities					
Net income	$ 162,551	$ 162,551	$ 60,072	$ (222,623)	$ 162,551
Adjustments to reconcile net income to net cash provided by continuing operating activities:					
Income from discontinued operations	—	(3,150)	—	—	(3,150)
Depreciation and amortization	—	82,536	28,193	—	110,729
Earnings in equity investments, net of distributions	88,550	14,598	1,576	(87,733)	16,991
Gains on sales of assets	—	(551)	(117)	—	(668)
Changes in assets and liabilities and other	(54,540)	(57,645)	22,884	53,571	(35,730)
Net cash provided by continuing operating activities	196,561	198,339	112,608	(256,785)	250,723
Cash flows from discontinued operations	—	3,782	—	—	3,782
Net cash provided by operating activities	196,561	202,121	112,608	(256,785)	254,505
Cash flows from investing activities	(278,806)	(31,529)	(180,486)	139,906	(350,915)
Cash flows from financing activities	80,107	(184,126)	65,097	119,029	80,107
Net increase in cash and cash equivalents	(2,138)	(13,534)	(2,781)	2,150	(16,303)
Cash and cash equivalents at beginning of period	4,116	13,596	2,826	(4,116)	16,422
Cash and cash equivalents at end of period	$ 1,978	$ 62	$ 45	$ (1,966)	$ 119

TEPPCO PARTNERS, L.P.

Notes To Consolidated Financial Statements—(Continued)

	Year Ended December 31, 2004 (as restated)				
	TEPPCO Partners, L.P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
			(in thousands)		
Cash flows from continuing operating activities					
Net income	$ 138,548	$ 138,548	$ 63,998	$ (202,546)	$ 138,548
Adjustments to reconcile net income to net cash provided by continuing operating activities:					
Income from discontinued operations	—	(2,689)	—	—	(2,689)
Depreciation and amortization	—	89,438	22,846	—	112,284
Earnings in equity investments, net of distributions	94,509	(130)	8,208	(77,522)	25,065
Gains on sales of assets	—	(526)	(527)	—	(1,053)
Changes in assets and liabilities and other	(158,726)	29,707	(30,930)	151,690	(8,259)
Net cash provided by continuing operating activities	74,331	254,348	63,595	(128,378)	263,896
Cash flows from discontinued operations	—	3,271	—	—	3,271
Net cash provided by operating activities	74,331	257,619	63,595	(128,378)	267,167
Cash flows from continuing investing activities	98	(26,662)	(40,864)	(115,331)	(182,759)
Cash flows from discontinued investing activities	—	(7,398)	—	—	(7,398)
Cash flows from investing activities	98	(34,060)	(40,864)	(115,331)	(190,157)
Cash flows from financing activities	(90,057)	(229,206)	(25,575)	254,781	(90,057)
Net decrease in cash and cash equivalents	(15,628)	(5,647)	(2,844)	11,072	(13,047)
Cash and cash equivalents at beginning of period	19,744	19,243	5,670	(15,188)	29,469
Cash and cash equivalents at end of period	$ 4,116	$ 13,596	$ 2,826	$ (4,116)	$ 16,422

	Year Ended December 31, 2003 (as restated)				
	TEPPCO Partners, L.P.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	TEPPCO Partners, L.P. Consolidated
			(in thousands)		
Cash flows from operating activities					
Net income	$ 121,780	$ 121,780	$ 45,073	$ (166,853)	$ 121,780
Adjustments to reconcile net income to net cash provided by operating activities:					
Depreciation and amortization	—	80,114	20,614	—	100,728
Earnings in equity investments, net of distributions	80,718	7,548	2,482	(75,619)	15,129
Gain on sale of assets	—	—	(3,948)	—	(3,948)
Changes in assets and liabilities and other	48,432	5,576	1,075	(46,348)	8,735
Net cash provided by operating activities	250,930	215,018	65,296	(288,820)	242,424
Cash flows from continuing investing activities	(175,568)	(164,872)	(37,589)	203,531	(174,498)
Cash flows from investing activities	—	(13,810)	—	—	(13,810)
Cash flows from discontinued investing activities	(175,568)	(178,682)	(37,589)	203,531	(188,308)
Cash flows from financing activities	(55,618)	(25,340)	(44,758)	70,101	(55,615)
Net increase (decrease) in cash and cash equivalents	19,744	10,996	(17,051)	(15,188)	(1,499)
Cash and cash equivalents at beginning of period	—	8,247	22,721	—	30,968
Cash and cash equivalents at end of period	$ 19,744	$ 19,243	$ 5,670	$ (15,188)	$ 29,469

TEPPCO PARTNERS, L P

Notes To Consolidated Financial Statements—(Continued)

Note 20. Restatement of Consolidated Financial Statements

We are restating our previously reported consolidated financial statements for the fiscal years ended December 31, 2003 and 2004 For the impact of the restated consolidated financial results for the quarterly periods during the years ended December 31, 2005 and 2004, see Note 21 We have determined that our method of accounting for the $33 4 million excess investment in Centennial, previously described as an intangible asset with an indefinite life, and the $27 1 million excess investment in Seaway, previously described as equity method goodwill, was incorrect Through our accounting for these excess investments in Centennial and Seaway as intangible assets with indefinite lives and equity method goodwill, respectively, we have been testing the amounts for impairment on an annual basis as opposed to amortizing them over a determinable life We determined that it would be more appropriate to account for these excess investments as intangible assets with determinable lives As a result, we made non-cash adjustments that reduced the net value of the excess investments in Centennial and Seaway, and increased amortization expense allocated to our equity earnings The effect of this restatement caused a $3 8 million and $4 0 million reduction to net income as previously reported for the fiscal years ended December 31, 2004 and 2003, respectively As a result of the accounting correction, net income for the fiscal year ended December 31, 2005, includes a charge of $4 8 million, of which $3 8 million relates to the first nine months Additionally, partners' capital at December 31, 2002, reflects a $2 5 million reduction representing the cumulative effect of this correction for fiscal years ended December 31, 2000 through 2002

While we believe the impacts of these non-cash adjustments are not material to any previously issued financial statements, we determined that the cumulative adjustment for these non-cash items was too material to record in the fourth quarter of 2005, and therefore it was most appropriate to restate prior periods' results. These non-cash adjustments had no effect on our operating income, compensation expense, debt balances or ability to meet all requirements related to our debt facilities The restatement had no impact on total cash flows from operating activities, investing activities or financing activities All amounts in the accompanying consolidated financial statements have been adjusted for this restatement

We will continue to amortize the $30 0 million excess investment in Centennial related to a contract using units-of-production methodology over a 10-year life The remaining $3 4 million related to a pipeline will continue to be amortized on a straight-line basis over 35 years We will continue to amortize the $27 1 million excess investment in Seaway on a straight-line basis over a 39-year life related primarily to a pipeline

The following tables summarize the impact of the restatement adjustment on previously reported balance sheet amounts for the year ended December 31, 2004, and income statement amounts and cash flow amounts for the years ended December 31, 2004 and 2003 (in thousands)

Balance Sheet Amounts;

	December 31, 2004		
	As Previously Reported	Adjustment	As Restated
Equity investments	$ 373,652	$ (10,345)	$ 363,307
Total assets	$ 3,196,629	$ (10,345)	$ 3,186,284
Capital:			
General partner's interest	$ (33,006)	$ (2,875)	$ (35,881)
Limited partners' interest	1,054,454	(7,470)	1,046,984
Total partners' capital	1,021,448	(10,345)	1,011,103
Total liabilities and partners' capital	$ 3,196,629	$ (10,345)	$ 3,186,284

TEPPCO PARTNERS, L.P.
Notes To Consolidated Financial Statements—(Continued)

Income Statement Amounts:

	Years Ended December 31, 2004		Years Ended December 31, 2003	
Equity earnings as previously reported	$	25,981	$	16,863
Adjustment for amortization of excess investments		(3,833)		(3,989)
Equity earnings as restated	$	22,148	$	12,874
Net income as previously reported	$	142,381	$	125,769
Adjustment for amortization of excess investments		(3,833)		(3,989)
Net income as restated	$	138,548	$	121,780
Net Income Allocation as previously reported:				
Limited Partner Unitholders	$	101,307	$	89,191
Class B Unitholder		—		1,806
General Partner		41,074		34,772
Total net income allocated	$	142,381	$	125,769
Basic and diluted net income per Limited Partner and Class B Unit as previously reported	$	1.61	$	1.52
Net Income Allocation as restated:				
Limited Partner Unitholders	$	98,580	$	86,357
Class B Unitholder		—		1,754
General Partner		39,968		33,669
Total net income allocated as restated	$	138,548	$	121,780
Basic and diluted net income per Limited Partner and Class B Unit as restated	$	1.56	$	1.47

Cash Flow Amounts:

Year Ended December 31, 2004	As Previously Reported		Adjustment		As Restated	
Cash flows from operating activities:						
Net income	$	142,381	$	(3,833)	$	138,548
Earnings in equity investments, net of distributions		21,232		3,833		25,065

Year Ended December 31, 2003	As Previously Reported		Adjustment		As Restated	
Cash flows from operating activities:						
Net income	$	125,769	$	(3,989)	$	121,780
Earnings in equity investments, net of distributions		11,140		3,989		15,129

TEPPCO PARTNERS, L.P.

Notes To Consolidated Financial Statements—(Continued)

Partners' Capital Amounts:

	Outstanding Limited Partner Units	General Partner's Interest	Limited Partners' Interests	Accumulated Other Comprehensive Loss	Total
2002:					
Partners' capital at December 31, 2002 as previously reported	53,809,597	$ 12,770	$ 899,127	$ (20,055)	$ 891,842
Restatement adjustment	—	(666)	(1,727)	—	(2,393)
Partners' capital at December 31, 2002 as restated (unaudited)	53,809,597	$ 12,104	$ 897,400	$ (20,055)	$ 889,449
2003:					
Partners' capital at December 31, 2003 as previously reported	62,998,554	$ (7,181)	$ 1,119,404	$ (2,902)	$ 1,109,321
Restatement adjustment	—	(1,769)	(4,743)	—	(6,512)
Partners' capital at December 31, 2003 as restated	62,998,554	$ (8,950)	$ 1,114,661	$ (2,902)	$ 1,102,809
2004:					
Partners' capital at December 31, 2004 as previously reported	62,998,554	$ (33,006)	$ 1,054,454	$ —	$ 1,021,448
Restatement adjustment	—	(2,875)	(7,470)	—	(10,345)
Partners' capital at December 31, 2004 as restated	62,998,554	$ (35,881)	$ 1,046,984	$ —	$ 1,011,103

Note 21. Quarterly Financial Information (Unaudited)

	First Quarter (as restated)	Second Quarter (as restated)	Third Quarter (as restated)	Fourth Quarter (as restated)
	(in thousands, except per Unit amounts)			
2005: (1)				
Operating revenues	$ 1,523,791	$ 2,087,385	$ 2,500,127	$ 2,493,731
Operating income	61,232	53,817	43,378	61,606
Income from continuing operations:				
As previously reported	$ 47,457	$ 41,387	$ 30,231	$ 44,137
Restatement adjustment	(1,152)	(1,311)	(1,348)	—
As restated	$ 46,305	$ 40,076	$ 28,883	$ 44,137
Income from discontinued operations	$ 1,124	$ 846	$ 692	$ 488
Net income:				
As previously reported	$ 48,581	$ 42,233	$ 30,923	$ 44,625
Restatement adjustment	(1,152)	(1,311)	(1,348)	—
As restated	$ 47,429	$ 40,922	$ 29,575	$ 44,625
Basic and diluted net income per Limited Partner Unit from continuing operations:(2)(3)				
As previously reported	$ 0.54	$ 0.44	$ 0.30	$ 0.45
Restatement adjustment	(0.01)	(0.02)	(0.01)	—
As restated	$ 0.53	$ 0.42	$ 0.29	$ 0.45
Basic and diluted net income per Limited Partner Unit from discontinued operations(3)	$ 0.01	$ 0.01	$ 0.01	$ —
Basic and diluted net income per Limited Partner Unit:(2)(3)				
As previously reported	$ 0.55	$ 0.45	$ 0.31	$ 0.45
Restatement adjustment	(0.01)	(0.02)	(0.01)	—
As restated	$ 0.54	$ 0.43	$ 0.30	$ 0.45

TEPPCO PARTNERS, L P

Notes To Consolidated Financial Statements—(Continued)

	First Quarter (as restated)	Second Quarter (as restated)	Third Quarter (as restated)	Fourth Quarter (as restated)
	(in thousands, except per Unit amounts)			
2004: (1)				
Operating revenues	$ 1,315,942	$ 1,352,107	$ 1,487,556	$ 1,792,485
Operating income	53,457	41,990	36,361	52,636
Income from continuing operations:				
As previously reported	$ 39,989	$ 37,348	$ 25,135	$ 37,220
Restatement adjustment	(713)	(1,129)	(1,085)	(906)
As restated	$ 39,276	$ 36,219	$ 24,050	$ 36,314
Income from discontinued operations	$ 444	$ 411	$ 720	$ 1,114
Net income:				
As previously reported	$ 40,433	$ 37,759	$ 25,855	$ 38,334
Restatement adjustment	(713)	(1,129)	(1,085)	(906)
As restated	$ 39,720	$ 36,630	$ 24,770	$ 37,428
Basic and diluted net income per Limited Partner Unit from continuing operations:				
As previously reported	$ 0 45	$ 0 43	$ 0 28	$ 0 42
Restatement adjustment	(0.01)	(0.02)	(0.01)	(0.01)
As restated	$ 0.44	$ 0.41	$ 0 27	$ 0.41
Basic and diluted net income per Limited Partner Unit from discontinued operations	$ 0.01	$ —	$ 0.01	$ 0.01
Basic and diluted net income per Limited Partner Unit:				
As previously reported	$ 0 46	$ 0.43	$ 0.29	$ 0.43
Restatement adjustment	(0.01)	(0.02)	(0.01)	(0.01)
As restated	$ 0.45	$ 0.41	$ 0.28	$ 0.42

(1) The quarterly financial information for 2004 and the first three quarters of 2005 reflect the impact of the restatement

(2) The sum of the four quarters does not equal the total year due to rounding

(3) Per Unit calculation includes 6,965,000 Units issued in May and June 2005

Note 22. Subsequent Events

In January 2006, we entered into interest rate swaps with a total notional amount of $200 0 million, whereby we will receive a floating rate of interest and will pay a fixed rate of interest for a two-year term These interest rate swaps were executed to decrease the exposure to potential increases in floating interest rates Using the balances of outstanding debt at December 31, 2005, these interest rate swaps decrease the level of floating interest rate debt from 41% to 29% of total outstanding debt

On February 13, 2006, we and an affiliate of Enterprise entered into a letter agreement related to an additional expansion (the "Jonah Expansion") of the Jonah system (the "Letter Agreement") The Jonah Expansion will consist of the installation of approximately 90,000 horsepower of gas turbine compression at a new compression station, related new piping and certain related facilities, which is expected to increase capacity of the Jonah system from 1 5 billion cubic feet per day to 2 0 billion cubic feet per day We expect to enter into a joint venture ("Joint Venture") agreement with Enterprise relating to the construction and financing of the Jonah Expansion Enterprise will be responsible for all activities relating to the construction of the Jonah Expansion and will advance all amounts necessary to plan, engineer, construct or complete the Jonah Expansion (anticipated to be approximately $200 0 million) Such advance will constitute a subscription for an equity interest in the proposed Joint Venture (the "Subscription") We expect the Jonah Expansion to be put into service in late 2006 We have the option to return to Enterprise up to 100% of the amount of the Subscription If we return a portion of the Subscription to Enterprise, our relative interests in the proposed Joint Venture will be adjusted accordingly The proposed Joint Venture will terminate without liability to either party if we return 100% of the Subscription

Table of Contents

TEPPCO PARTNERS, L.P.

Notes To Consolidated Financial Statements—(Continued)

Part IV, Exhibits and Financial Statement Schedule, Exhibit No. 12

COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES

The ratio of earnings to fixed charges is calculated using the Securities and Exchange Commission guidelines(a).

	Year Ended December 31,				
	2005	2004	2003	2002	2001
	(dollars in millions)				
Earnings as defined for fixed charges calculation					
Add:					
Pretax income (loss) from continuing operations(b)(e)	$ 2,951	$ 891	$ (839)	405	943
Fixed charges	847	1,115	1,245	1,219	846
Distributed income of equity investees	473	140	263	369	156
Deduct:					
Preference security dividend requirements of consolidated subsidiaries	27	32	102	157	165
Interest capitalized(c)	15	14	46	161	112
Total earnings (as defined for the Fixed Charges calculation)	$ 4,229	$ 2,100	$ 521	$ 1,675	$ 1,668
Fixed charges:					
Interest on debt, including capitalized portions	$ 796	$ 1,057	$ 1,116	$ 1,041	$ 659
Estimate of interest within rental expense	24	26	27	21	22
Preference security dividend requirements of consolidated subsidiaries	27	32	102	157	165
Total fixed charges	$ 847	$ 1,115	$ 1,245	$ 1,219	$ 846
Ratio of earnings to fixed charges(d)	5.0	1.9	(d)	1.4	2.0

(a) Income Statement amounts have been adjusted for discontinued operations

(b) Excludes minority interest expenses and income or loss from equity investees.

(c) Excludes equity costs related to Allowance for Funds Used During Construction that are included in Other Income and Expenses in the Consolidated Statements of Operations

(d) Earnings were inadequate to cover fixed charges by $724 million for the year ended December 31, 2003.

(e) Includes pre-tax gains on the sale of TEPPCO GP and LP of approximately $0.9 billion, net of minority interest, in 2005

Table of Contents

PART IV

EXHIBIT INDEX

Exhibits filed herewith are designated by an asterisk (*) All exhibits not so designated are incorporated by reference to a prior filing, as indicated Items constituting management contracts or compensatory plans or arrangements are designated by a double asterisk (**). Portions of the exhibit designated by a triple asterisk (***) have been omitted and filed separately with the Securities and Exchange Commission pursuant to a request for confidential treatment pursuant to Rule 24b-2 under the Securities and Exchange Act of 1934

Exhibit Number	
2.1	Agreement and Plan of Merger, dated as of May 8, 2005, as amended as of July 11, 2005, as of October 3, 2005 and as of March 30, 2006, by and among the registrant, Duke Energy Corporation, Cinergy Corp , Deer Acquisition Corp , and Cougar Acquisition Corp (filed with Form 8-K of Duke Energy Corporation, File No 1-32853, April 4, 2006, as Exhibit 2-1)
2 2	Amended and Restated Combination Agreement dated as of September 20, 2001, among Duke Energy Corporation, 3058368 Nova Scotia Company, 3946509 Canada Inc and Westcoast Energy Inc. (filed with Form 10-Q of Duke Energy Carolinas, LLC for the quarter ended September 30, 2001, File No 1-4928, as Exhibit 10-7)
2 3	Separation and Distribution Agreement, dated s of December 13, 2006, by and between Duke Energy Corporation and Spectra Energy Corp (filed with the Form 8-K of Duke Energy Corporation. File No 1-32853, December 15, 2006, as Exhibit 2 1)
3 1	Amended and restated Certificate of Incorporation (filed with the Form 8-K of Duke Energy Corporation, File No 1-32853, April 4, 2006, as Exhibit 3-1)
3.2	Amended and Restated By-Laws of registrant (filed with the Form 8-K of Duke Energy Corporation, File No 1-32853, April 4, 2006, as Exhibit 3 2)
4	Rights Agreement, dated as of December 17, 1998, between the registrant and The Bank of New York, as Rights Agent (filed with the Form 8-K of Duke Energy Carolinas, LLC, dated February 11, 1999, File No 1-4928, as Exhibit 4-1)
4.1	Amendment No 1, dated as of May 8, 2005, to the Rights Agreement, dated as of December 17, 1998, between the registrant and The Bank of New York, as rights agent (filed with the Form 8-K of Duke Energy Carolinas, LLC, May 12, 2005, File No 1-4928, as Exhibit 4-1)
10 1	Purchase and Sale Agreement dated as of February 24, 2005, by and between Enterprise GP Holdings LP and Duke Energy Field Services, LLC (filed with Form 10-K of Duke Energy Carolinas, LLC for the year ended December 31, 2004, File No 1-4928, as Exhibit 10-25)
10 2	Term Sheet Regarding the Restructuring of Duke Energy Field Services LLC dated as of February 23, 2005, between Duke Energy Corporation and ConocoPhillips (filed with Form 10-K of Duke Energy Carolinas, LLC for the year ended December 31, 2004, File No 1-4928, as Exhibit 10-26)
10 3	Reorganization Agreement by and among ConocoPhillips, Duke Capital LLC and Duke Energy Field Services, LLC dated as of May 26, 2005 (filed with Form 10-Q of Duke Energy Carolinas, LLC for the quarter ended June 30, 2005, File No 1-4928, as Exhibit 10-4)
10 3.1	First Amendment to Reorganization Agreement by and among ConocoPhillips, Duke Capital LLC and Duke Energy Field Services, LLC dated as of June 30, 2005 (filed with Form 10-Q of Duke Energy Carolinas, LLC for the quarter ended June 30, 2005, File No 1-4928, as Exhibit 10-4 1)
10 3.2	Second Amendment to Reorganization Agreement by and among ConocoPhillips, Duke Capital LLC and Duke Energy Field Services, LLC dated as of July 11, 2005 (filed with Form 10-Q of Duke Energy Carolinas, LLC for the quarter ended June 30, 2005, File No 1-4928, as Exhibit 10-4 2)
10 4	Purchase and Sale Agreement dated as of January 8, 2006, by and among Duke Energy Americas, LLC, and LSP Bay II Harbor Holding, LLC (filed with the Form 10-Q of the registrant for the quarter ended March 31, 2006, File No 1-32853, as Exhibit 10 2)

PART IV

Exhibit Number	
10 4 1	Amendment to Purchase and Sale Agreement, dated as of May 4, 2006, by and among Duke Energy Americas, LLC, LS Power Generation, LLC (formerly known as LSP Bay II Harbor Holding, LLC), LSP Gen Finance Co, LLC, LSP South Bay Holdings, LLC, LSP Oakland Holdings, LLC, and LSP Morro Bay Holdings, LLC ((filed with the Form 10-Q of the registrant for the quarter ended March 31, 2006, File No 1-32853, as Exhibit 10 2.1)
10 5	Second Amended and Restated Limited Liability Company Agreement of Duke Energy Field Services, LLC by and between ConocoPhillips Gas Company and Duke Energy Enterprises Corporation, dated as of July 5, 2005 (filed with the Form 10-K of Duke Energy Carolinas, LLC for the year ended December 31, 2005, File No 1-4928, as Exhibit 10 5)
10 6	Limited Liability Company Agreement of Gulfstream Management & Operating Services, LLC dated as of February 1, 2001 between Duke Energy Gas Transmission Corporation and Williams Gas Pipeline Company (filed with Form 10-K of Duke Energy Carolinas, LLC for the year ended December 31, 2002, File No 1-4928, as Exhibit 10-18).
10 7	Formation Agreement between PanEnergy Trading and Market Services, Inc and Mobil Natural Gas, Inc dated May 29, 1996 (filed with Form 10-Q of PanEnergy Corp for the quarter ended June 30, 1996, File No. 1-8157, as Exhibit 2).
10 8***	Master Transaction Agreement by and among Duke Energy Marketing America, LLC, Duke Energy North America, LLC, Duke Energy Trading and Marketing, L. L. C , Duke Energy Marketing Limited Partnership, Engage Energy Canada, L P and Barclay Bank PLC, dated as of November 17, 2005 (filed with the Form 10-K of Duke Energy Carolinas, LLC for the year ended December 31, 2005, File No 1-4928, as Exhibit 10 8)
10 9	$800,000,000 364-Day Credit Agreement dated as of June 29, 2005, among Duke Capital LLC, the banks listed therein, JPMorgan Chase Bank, N.A , as Administrative Agent, and Barclays Bank, PLC, as Syndication Agent (filed with Form 10-Q of Duke Energy Carolinas, LLC for the quarter ended June 30, 2005, File No 1-4928, as Exhibit 10-3).
10 10	$600,000,000 Amended and Restated Credit Agreement dated as of June 30, 2005, among Duke Capital LLC, the banks listed therein, JPMorgan Chase Bank, N A , as Administrative Agent, and Wachovia Bank, National Association, as Syndication Agent (filed with Form 10-Q of Duke Energy Carolinas, LLCfor the quarter ended June 30, 2005, File No 1-4928, as Exhibit 10-2)
10 11	$500,000,000 Amended and Restated Credit Agreement dated as of June 30, 2005, among the registrant, the banks listed therein, Citibank N A , as Administrative Agent, and Bank of America, N A , as Syndication Agent (filed with Form 10-Q of Duke Energy Carolinas, LLCfor the quarter ended June 30, 2005, File No 1-4928, as Exhibit 10-1)
10 12	Loan Agreement dated as of February 25, 2005 between Duke Energy Field Services, LLC and Duke Capital LLC (filed with Form 10-Q of Duke Energy Carolinas, LLCfor the quarter ended March 31, 2005, File No 1-4928, as Exhibit 10-3)
10 13	Accelerated Share Acquisition Plan, dated March 18, 2005, between registrant and Merrill Lynch International (filed with Form 10-Q of Duke Energy Carolinas, LLCfor the quarter ended March 31, 2005, File No 1-4928, as Exhibit 10-4)
10 14**	Directors' Charitable Giving Program (filed with Form 10-K of Duke Energy Carolinas, LLCfor the year ended December 31, 1992, File No 1-4928, as Exhibit 10-P).
10 14.1**	Amendment to Directors' Charitable Giving Program dated June 18, 1997 (filed with Form 10-K of Duke Energy Carolinas, LLCfor the year ended December 31, 2003, File No 1-4928, as Exhibit 10-1 1)
10 14.2**	Amendment to Directors' Charitable Giving Program dated July 28, 1997 (filed with Form 10-K of Duke Energy Carolinas, LLC for the year ended December 31, 2003, File No 1-4928, as Exhibit 10-1 2)
10 14.3**	Amendment to Directors' Charitable Giving Program dated February 18, 1998 (filed with Form 10-K of Duke Energy Carolinas, LLCfor the year ended December 31, 2003, File No 1-4928, as Exhibit 10-1 3).
10 15**	Duke Energy Corporation 1998 Long-Term Incentive Plan, as amended (filed as Exhibit 1 to Schedule 14A of Duke Energy Carolinas, LLC, March 28, 2003, File No 1-4928).
10 16**	Duke Energy Corporation Executive Short-Term Incentive Plan (filed as Exhibit 2 to Schedule 14A of Duke Energy Carolinas, LLC, March 28, 2003, File No 1-4928)

Table of Contents

PART IV

Exhibit Number	
10 17**	Duke Energy Corporation Executive Savings Plan, as amended and restated (filed with Form 10-K of Duke Energy Carolinas, LLCfor the year ended December 31, 2003, File No 1-4928, as Exhibit 10-6)
10 17.1**	Amendment No 1 to the Duke Energy Corporation Executive Savings Plan, dated October 27, 2004, effective December 31, 2004 (filed with Form 10-K of Duke Energy Carolinas, LLCfor the year ended December 31, 2004, File No 1-4928, as Exhibit 10-6 1)
*10 17.2**	Amendment to the Duke Energy Corporation Executive Savings Plan, effective December 18, 2006
*10 17 3**	Amendment to the Duke Energy Corporation Executive Savings Plan I & II, effective December 19, 2006
10 18**	Duke Energy Corporation Executive Cash Balance Plan (filed with Form 10-K of TEPPCO Partners, LP, File No 1-10403, for the year ended December 31, 1999, as Exhibit 10-8)
10 18.1**	Amendment No 1 to the Duke Energy Corporation Executive Cash Balance Plan, dated August 26, 1999 (filed with Form 10-K of Duke Energy Carolinas, LLCfor the year ended December 31, 2004, File No 1-4928, as Exhibit 10-7 1)
10.18.2**	Amendment No 2 to the Duke Energy Corporation Executive Cash Balance Plan, dated March 6, 2000 (filed with Form 10-K of Duke Energy Carolinas, LLCfor the year ended December 31, 2004, File No 1-4928, as Exhibit 10-7 2)
10 18.3**	Amendment No 3 to the Duke Energy Corporation Executive Cash Balance Plan, dated December 21, 2000 (filed with Form 10-K of Duke Energy Carolinas, LLCfor the year ended December 31, 2004, File No 1-4928, as Exhibit 10-7 3)
10 18 4**	Amendment No 4 to the Duke Energy Corporation Executive Cash Balance Plan, dated October 27, 2004, effective December 31, 2004 (filed with Form 10-K of Duke Energy Carolinas, LLCfor the year ended December 31, 2004, File No 1-4928, as Exhibit 10-7 4)
*10 18.5**	Amendment to the Duke Energy Corporation Executive Cash Balance Plan, effective December 1, 2006
*10 18.6**	Amendment to the Duke Energy Corporation Executive Cash Balance Plan I & II, effective December 31, 2006
10 19**	Duke Energy Corporation Retirement Benefit Equalization Plan (filed with Form 10-K of TEPPCO Partners, LP, File No 1-10403, for the year ended December 31, 1999, as Exhibit 10 9)
*10 19.1	Amendment to the Duke Energy Corporation Retirement Benefit Equalization Plan, effective December 21, 2006
10 20**	Form of Key Employee Severance Agreement and Release between Duke Energy Corporation and certain key executives (filed with Form 10-K of Duke Energy Carolinas, LLCfor the year ended December 31, 1999, File No 1-4928, as Exhibit 10-BB)
10 21**	Form of Change in Control Agreement between Duke Energy Corporation and certain key executives (filed with Form 10-K of Duke Energy Carolinas, LLCfor the year ended December 31, 1999, File No 1-4928, as Exhibit 10-CC)
10 22**	Form of Change in Control Agreement between Duke Energy Corporation and certain key executives dated as of July 1, 2005 (filed with Form 8-K of Duke Energy Carolinas, LLC dated August 24, 2005, File No 1-4928, as Exhibit 10-1)
10 23**	Employment Agreement dated November 2003 between Paul M Anderson and Duke Energy Corporation (filed with Form 10-K of Duke Energy Carolinas, LLCfor the year ended December 31, 2003, File No 1-4928, as Exhibit 10-18)
10 23.1**	First Amendment to Employment Agreement dated March 9, 2004 between Paul M Anderson and Duke Energy Corporation (filed with Form 10-K of Duke Energy Carolinas, LLCfor the year ended December 31, 2003, File No 1-4928, as Exhibit 10-18 1)
10 23 2**	Performance Award Agreement dated November 17, 2003, pursuant to Duke Energy Corporation 1998 Long-Term Incentive Plan, by and between Duke Energy Corporation and Paul M Anderson (filed with Form 10-K of Duke Energy Carolinas, LLCfor the year ended December 31, 2004, File No 1-4928, as Exhibit 10-18 2)

Table of Contents

PART IV

Exhibit Number	
10 23.3**	Phantom Stock Agreement dated November 17, 2003, pursuant to Duke Energy Corporation 1998 Long-Term Incentive Plan, by and between Duke Energy Corporation and Paul M Anderson (filed with Form 10-K of Duke Energy Carolinas, LLCfor the year ended December 31, 2004, File No 1-4928, as Exhibit 10-18 3)
10 23 4**	Non-Qualified Option Agreement dated as of November 17, 2003 pursuant to Duke Energy Corporation 1998 Long-Term Incentive Plan, by and between Duke Energy Corporation and Paul M Anderson (filed with Form 10-K of Duke Energy Carolinas, LLCfor the year ended December 31, 2004, File No 1-4928, as Exhibit 10-18 4)
10 23 5**	Second Amendment to Employment Agreement, dated as of April 4, 2006, by and among Paul M Anderson, Duke Energy Holding Corp (subsequently renamed Duke Energy Corporation) and Duke Energy Corporation (subsequently renamed Duke Energy Carolinas, LLC) (filed with Form 8-K of Duke Energy Corporation, File No 1-32853, April 6, 2006, as Exhibit 10 5)
10 24**	Supplemental Compensation Agreement dated June 17, 1997 between Duke Power Company and Dr Ruth G Shaw (filed with Form 10-K of Duke Energy Carolinas, LLCfor the year ended December 31, 2003, File No 1-4928, as Exhibit 10-19)
10 24.1**	Severance and Retention Agreement between Duke Energy Corporation and Ruth Shaw, dated April 4, 2006 (filed with Form 8-K of Duke Energy Corporation, File No 1-32853, April 6, 2006, as Exhibit 10 7)
10 24.2**	Severance and Consulting Agreement between Duke Energy Corporation and Ruth Shaw, dated October 24, 2006 (filed with Form 8-K of Duke Energy Corporation, File No 1-32853, October 27, 2006, as Exhibit 10 2)
10 25**	Resolution of Board of Directors, February 22, 2005, Approving Award of Phantom Stock to Nonemployee Directors (filed with Form 10-Q of Duke Energy Carolinas, LLCfor the quarter ended March 31, 2005, File No 1-4928, as Exhibit 10-9)
10 26**	Resolution of Board of Directors, May 12, 2005, Approving Change to Retainer and Attendance Fees for Non-Employee Directors (filed with Form 10-Q of Duke Energy Carolinas, LLCfor the quarter ended June 30, 2005, File No 1-4928, as Exhibit 10-5)
10 27**	Form of Performance Award Agreement dated February 28, 2005, pursuant to Duke Energy Corporation 1998 Long-Term Incentive Plan by and between Duke Energy Corporation and each of Fred J Fowler, David L Hauser, Jimmy W Mogg and Ruth G Shaw (filed with the Form 8-K of Duke Energy Carolinas, LLC, File No 1-4928, February 28, 2006, as Exhibit 10-1)
10 28**	Form of Phantom Stock Award Agreement dated February 28, 2005, pursuant to Duke Energy Corporation 1998 Long-Term Incentive Plan by and between Duke Energy Corporation and each of Fred J Fowler, David L Hauser, Jimmy W Mogg and Ruth G Shaw (filed with the Form 8-K of Duke Energy Carolinas, LLC, File No 1-4928, February 28, 2005, as Exhibit 10-2)
10 29**	Form of Phantom Stock Award Agreement dated as of May 11, 2005, pursuant to Duke Energy Corporation 1998 Long-Term Incentive Plan by and between Duke Energy Corporation and Jimmy W Mogg (filed with Form 10-Q of Duke Energy Carolinas, LLC for the quarter ended June 30, 2005, File No 1-4928, as Exhibit 10-6)
10 30**	Form of Phantom Stock Award Agreement dated as of May 12, 2005, pursuant to Duke Energy Corporation 1998 Long-Term Incentive Plan by and between Duke Energy Corporation and nonemployee directors (filed in Form 8-K of Duke Energy Carolinas, LLC, May 17, 2005, File No 1-4928, as Exhibit 10-1)
10 31**	Agreement between Duke Energy Corporation and Jimmy W Mogg relating to certain retirement benefits, consisting of letter agreements dated May 25, 1995, August 4, 2001 and March 29, 2004 (filed with Form 10-K of Duke Energy Carolinas, LLCfor the year ended December 31, 2004, File No 1-4928, as Exhibit 10-23)
10 32**	First Amendment to Key Employee Severance Agreement and General Release between Duke Energy Corporation and Richard J Osborne, dated August 21, 2004 (filed with Form 10-Q of Duke Energy Carolinas, LLCfor the quarter ended October 31, 2004, File No 1-4928, as Exhibit 10-2)

[Table of Contents](#)

PART IV

Exhibit Number	
10 33**	Certification of Chairman and Chief Executive Officer 2004 Performance Goals (filed in Form 8-K of Duke Energy Carolinas, LLC, February 28, 2005, File No 1-4928, as item 1 of Item 1 01)
10 34**	Approval of Payment of 2004 Executive Officer Short-Term Incentives (filed in Form 8-K of Duke Energy Carolinas, LLC, February 28, 2005, File No 1-4928, as item 2 of Item 1 01)
10 35**	Establishment of Chairman and Chief Executive Officer 2005 Performance Goals (filed in Form 8-K of Duke Energy Carolinas, LLC, February 28, 2005, File No 1-4928, as item 3 of Item 1 01)
10 35.1**	Certification of Chairman and Chief Executive Officer 2005 Performance Goals (filed with Form 8-K of Duke Energy Carolinas, LLC, File No 1-4928, March 3, 2006, as item 1 of Item 1 01)
10 36**	Establishment of Financial Measure Portion of Chairman and Chief Executive Officer 2006 Performance Goals (filed in Form 8-K of Duke Energy Carolinas, LLC, December 22, 2005, File No 1-4928, as item 2 of Item 1 01).
10.37**	2005 Executive Officer Base Salaries, Short-Term Incentive Opportunities and Long-Term Incentive Opportunities (filed in Form 8-K of Duke Energy Carolinas, LLC, February 28, 2005, File No 1-4928, as item 4 of Item 1 01).
10 38**	2006 Executive Officer Base Salaries and Short-Term Incentive Opportunities (filed in Form 8-K of Duke Energy Carolinas, LLC December 22, 2005, File No 1-4928, as item 1 of Item 1 01)
10 38.1**	Final Approval of 2006 Executive Officer Financial Performance Target for Short-Term Incentive Opportunity (filed with Form 8-K of Duke Energy Carolinas, LLC, File No 1-4928, March 3, 2006, as item 3 of Item 1 01).
10 39	Approval of Payment of 2005 Executive Officer Short-Term Incentives (filed with Form 8-K of Duke Energy Carolinas, LLC, File No 1-4928, March 3, 2006, as item 2 of Item 1 01).
10 40	Form of Phantom Stock Award Agreement (filed with Form 8-K of Duke Energy Corporation, File No 1-32853, April 4, 2006, as Exhibit 10 1).
10 41	Form of Performance Share Award Agreement (filed with Form 8-K of Duke Energy Corporation, File No 1-32853, April 4, 2006, as Exhibit 10 2)
10 42**	Employment Agreement between Duke Energy Corporation and James E Rogers, dated April 4, 2006 (filed with Form 8-K of Duke Energy Corporation, File No 1-32853, April 6, 2006, as Exhibit 10 1).
10.42.1**	Performance Award Agreement between Duke Energy Corporation and James E Rogers, dated April 4, 2006 (filed with Form 8-K of Duke Energy Corporation, File No 1-32853, April 6, 2006, as Exhibit 10 2)
10 42.2**	Phantom Stock Grant Agreement between Duke Energy Corporation and James E Rogers, dated April 4, 2006 (filed with Form 8-K of Duke Energy Corporation, File No 1-32853, April 6, 2006, as Exhibit 10 3)
10 42.3**	Stock Option Grant Agreement between Duke Energy Corporation and James E Rogers, dated April 4, 2006 (filed with Form 8-K of Duke Energy Corporation, File No 1-32853, April 6, 2006, as Exhibit 10 4)
10 43**	Retention Award Agreement between Duke Energy Corporation and David L Hauser, dated April 4, 2006 (filed with Form 8-K of Duke Energy Corporation, File No 1-32853, April 6, 2006, as Exhibit 10 6)
10 44**	Summary of Director Compensation (filed with the Form 10-Q of Duke Energy Corporation for the quarter ended June 30, 2006, File No 1-32853, as Exhibit 10 13)
10 45**	Form Phantom Stock Award Agreement and Election to Defer (filed with Form 8-K of Duke Energy Corporation, File No 1-32853, May 16, 2006, as Exhibit 10 1)
10 46	Agreements with Piedmont Electric Membership Corporation, Rutherford Electric Membership Corporation and Blue Ridge Electric Membership Corporation to provide wholesale electricity and related power scheduling services from September 1, 2006 through December 31, 2021 (filed with the Form 10-Q of Duke Energy Corporation for the quarter ended June 30, 2006, File No 1-32853, as Exhibit 10 15)

Table of Contents

PART IV

Exhibit Number	
10 47	Agreement with Dynegy Inc. and Rockingham Power, L.L.C. to acquire an approximately 825 megawatt power plant located in Rockingham County, N C for approximately $195 million (filed with Form 8-K of Duke Energy Corporation, File No 1-32853, May 25, 2006, as Exhibit 10 1)
10 48	Purchase and Sale Agreement by and among Cinergy Capital & Trading, Inc , as Seller, and Fortis Bank, S A /N V , as Buyer, dated as of June 26, 2006 (filed with Form 8-K of Duke Energy Corporation, File No 1-32853, June 30, 2006, as Exhibit 10 1)
10 49	Amended and Restated Credit Agreement, dated June 29, 2006, among Cinergy Corp , CG&E, PSI, ULH&P, The Banks Listed Herein, Barclays Bank PLC, as Administrative Agent, and JPMorgan Chase Bank, N A , as Syndication Agent (filed with the Form 10-Q of Duke Energy Corporation for the quarter ended June 30, 2006, File No 1-32853, as Exhibit 10 18)
10 50	Amended and Restated Credit Agreement, dated June 29, 2006, among Duke Capital LLC, The Banks Listed Herein, JPMorgan Chase Bank, N A , as Administrative Agent, and Wachovia Bank, National Association, as Syndication Agent (filed with the Form 10-Q of Duke Energy Corporation for the quarter ended June 30, 2006, File No 1-32853, as Exhibit 10 19)
10.51	Amended and Restated Credit Agreement, dated June 29, 2006, among Duke Energy Carolinas, LLC, The Banks Listed Herein, Citibank N.A., as Administrative Agent, and Banc of America, N A , as Syndication Agent (filed with the Form 10-Q of Duke Energy Corporation for the quarter ended June 30, 2006, File No 1-32853, as Exhibit 10 20)
10 52**	Form of Amendment to Performance Award Agreement and Phantom Stock Award Agreement (filed with Form 8-K of Duke Energy Corporation, File No 1-32853, August 24, 2006, as Exhibit 10 1)
10 53**	Form of Amendment to Phantom Stock Award Agreement (filed with Form 8-K of Duke Energy Corporation, File No 1-32853, August 24, 2006, as Exhibit 10 2)
10 54	Formation and Sale Agreement by and among Duke Ventures, LLC, Crescent Resources, LLC, Morgan Stanley Real Estate Fund V U S L P , Morgan Stanley Real Estate Fund V Special U S , L P , Morgan Stanley Real Estate Investors V U S , L P , MSP Real Estate Fund V, L P , and Morgan Stanley Strategic Investments, Inc , dated as of September 7, 2006 (filed with the Form 10-Q of Duke Energy Corporation for the quarter ended September 30, 2006, File No 1-32853, as Exhibit 10 3)
10 55	Amendment No 1 to Credit Agreement ("Amendment") dated as of February 28, 2006, by and among Duke Energy Carolinas, LLC (formerly known as Duke Energy Corporation), the banks listed therein, Citibank N A , as Administrative Agent, and Bank of America, N A , as Syndication Agent (filed with Form 8-K of Duke Energy Carolinas, LLC, File No 1-4928, March 30, 2006, as Exhibit 10 1)
10 56	Fifteenth Supplemental Indenture, dated as of April 3, 2006, among the registrant, Duke Energy and JPMorgan Chase Bank, N A (as successor to Guaranty Trust Company of New York), as trustee (the "Trustee"), supplementing the Senior Indenture, dated as of September 1, 1998, between Duke Energy Carolinas, LLC (formerly Duke Energy Corporation) and the Trustee (filed with the Form 10-Q of Duke Energy Corporation for the quarter ended June 30, 2006, File No 1-32853, as Exhibit 10 1)
10 57	Amendment No 1 to the Twelfth Supplemental Indenture, dated as of April 1, 2006 ("Amendment No 1"), among the registrant, Duke Energy and the Trustee, which amends the Twelfth Supplemental Indenture, dated as of May 7, 2003, between the registrant and the Trustee, pursuant to which the Convertible Notes were issued (filed with the Form 10-Q of Duke Energy Corporation for the quarter ended June 30, 2006, File No 1-32853, as Exhibit 10 3)
10 58**	Duke Energy Corporation 2006 Long-Term Incentive Plan (filed with Form 8-K of Duke Energy Corporation, File No 1-32853, October 27, 2006, as Exhibit 10 1)
10 59	Tax Matters Agreement, dated as of December 13, 2006, by and between Duke Energy Corporation and Spectra Energy Corp (filed with Form 8-K of Duke Energy Corporation, File No. 1-32853, December 15, 2006, as Exhibit 10 1)
10 60	Transition Services Agreement, dated as of December 13, 2006, by and between Duke Energy Corporation and Spectra Energy Corp (filed with Form 8-K of Duke Energy Corporation, File No 1-32853, December 15, 2006, as Exhibit 10 2)

[Table of Contents](#)

PART IV

Exhibit Number	
10 61	Employee Matters Agreement, dated as of December 13, 2006, by and between Duke Energy Corporation and Spectra Energy Corp (filed with Form 8-K of Duke Energy Corporation, File No 1-32853, December 15, 2006, as Exhibit 10 3)
10 62**	Agreement between Duke Energy Corporation and Fred J Fowler, dated December 19, 2006 (filed with Form 8-K of Duke Energy Corporation, File No 1-32853, December 22, 2006, as Exhibit 10 1).
*10 63**	Amendment to the Duke Energy Corporation Directors' Savings Plan I & II, effective December 19, 2006.
*10 64**	Amendment to the Cinergy Corp Excess Pension Plan, effective January 1, 2007
*10 65**	Amendment to the Cinergy Corp 401(k) Excess Plan, effective December 18, 2006
*10 66**	Amendment to the Cinergy Corp. Excess Profit Sharing Plan, effective December 19, 2006
*10 67**	Amendment to the Cinergy Corp. 401(k) Excess Plan, effective December 19, 2006
*10 68**	Amendment to the Cinergy Corp Directors' Deferred Compensation Plan, effective December 19, 2006.
*12	Computation of Ratio of Earnings to Fixed Charges.
*21	List of Subsidiaries.
*23 1	Consent of Independent Registered Public Accounting Firm
*23 2	Consent of Independent Registered Public Accounting Firm
*24 1	Power of attorney authorizing David L Hauser and others to sign the annual report on behalf of the registrant and certain of its directors and officers
*24 2	Certified copy of resolution of the Board of Directors of the registrant authorizing power of attorney
*31 1	Certification of the Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*31 2	Certification of the Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*32 1	Certification Pursuant to 18 U S C Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*32 2	Certification Pursuant to 18 U S C Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

The total amount of securities of the registrant or its subsidiaries authorized under any instrument with respect to long-term debt not filed as an exhibit does not exceed 10% of the total assets of the registrant and its subsidiaries on a consolidated basis The registrant agrees, upon request of the Securities and Exchange Commission, to furnish copies of any or all of such instruments to it.

Exhibit 10.17.2

AMENDMENT TO
DUKE ENERGY CORPORATION EXECUTIVE SAVINGS PLAN

The Duke Energy Corporation Executive Savings Plan (the "Plan") is amended, effective as of December 18, 2006, as follows:

1 Article II of the Duke Energy Corporation Executive Savings Plan I is hereby amended by adding a new subsection 2 30 at the end thereof as follows:

"2 30 "Duke Energy Retirement Cash Balance Plan" means the Duke Energy Retirement Cash Balance Plan as in effect on October 3, 2004, without giving effect to amendments adopted thereafter "

2\. Article II of the Duke Energy Corporation Executive Savings Plan is hereby amended by deleting the reference to the "Duke Energy Corporation 1998 Long-Term Incentive Plan" and substituting therefore the "Duke Energy Corporation 2006 Long-Term Incentive Plan"

3 Section 4 3 of the Duke Energy Corporation Executive Savings Plan II is hereby superseded and replaced in its entirety as set forth below:

"4 3 *Long-Term Incentive Plan Award Deferrals* Each eligible Participant may irrevocably elect to defer, in accordance with the terms of this Plan, the entire amount of any nonvested Award granted under a long-term incentive plan maintained by the Company (including the Company's 2006 Long-Term Incentive Plan), subject to the following conditions:

(1) Except as otherwise provided in this Section, the deferral election shall be made by, and shall become irrevocable as of, December 31 (or such earlier date as specified by the Company) of the calendar year next preceding the calendar year for which such Award is granted, or at such later time as is permitted by the Company, consistent with Section 409A of the Code, during the calendar year in which a Participant initially becomes eligible for the Plan

(2) To the extent permitted by the Company, and except as otherwise provided in Section 4 3(3), with respect to an Award that is subject to a forfeiture condition requiring the Participant's continued services for a period of at least thirteen (13) months from the date that the service provider obtains a "legally binding right" to such Award (within the meaning of Section 409A of the Code), the deferral election shall be made by, and shall become irrevocable as of, the thirtieth (30th) day following the date that the Participant obtains the legally binding right to such Award.

(3) To the extent permitted by the Company, with respect to an Award that constitutes "performance-based compensation" (within the meaning of Section 409A of the Code), the deferral election shall be made by, and shall become irrevocable as of, the date that is 6 months before the end of the applicable performance period (or such earlier date as specified by the Company), provided that in no event may such deferral election be made after such Award has become both substantially certain to be paid and readily ascertainable (within the meaning of Section 409A of the Code)

(4) Upon the date that an Award that the Participant has elected to defer would otherwise have been payable, the number of shares of stock or the cash payment that would have become so payable but for the deferral election shall be converted into an equal number of units in the Duke Energy Common Stock—Stock Deferrals Subaccount.

(5) Dividend Equivalents, to the extent deferred, shall also be deferred and credited to the Participant's Duke Energy Common Stock—Stock Deferrals Subaccount commencing on the payment date of the first cash dividend of Duke Energy Common Stock that is declared after the date on which the deferred Award vests

(6) No deferral of a stock option or restricted stock award shall be permissible."

4 Section 4 4 of the Duke Energy Corporation Executive Savings Plan II is hereby superseded and replaced in its entirety as set forth below:

"4 4 *Dividend Equivalents Deferrals* Each eligible Participant may irrevocably elect to defer, in accordance with the terms of this Plan, 100% of the amounts that would otherwise become payable as Dividend Equivalents, with respect to (i) an Award that is designated in the Award Agreement as a "Chairman's Award," or (ii) an Award with respect to which the Award Agreement specifically provides for the deferral of Dividend Equivalents Such election must be made by the Participant at the time the Participant elects to defer receipt of the related Award pursuant to the terms of Section 4 3. Dividend Equivalents that have been deferred pursuant to the first sentence of this Section and credited to the Participant's Account shall be credited to the Participant's Duke Energy Common Stock—Stock Deferrals Subaccount as of the dates such amounts would otherwise become payable pursuant to such award "

5 Section 4 5 of the Duke Energy Corporation Executive Savings Plan II is hereby amended by replacing the words "Eligible Pay" with the words "Eligible Earnings" and by replacing the words "Before Tax Savings" with the words "Before-Tax Elective Deferrals"

6 The last sentence of Section 7 1 of the Duke Energy Corporation Executive Savings Plan II is hereby deleted in its entirety

7 Except as explicitly set forth herein, the Plan will remain in full force and effect

This amendment has been approved and signed by an authorized officer of Duke Energy Corporation as of the date specified above

DUKE ENERGY CORPORATION

By: /S/ CHRISTOPHER C. ROLFE

Christopher C. Rolfe

Group Executive and Chief

Administrative Officer

Exhibit 10.17.3

AMENDMENT TO
DUKE ENERGY CORPORATION EXECUTIVE SAVINGS PLAN I & II
(as Amended and Restated effective January 1, 2003)

The Duke Energy Corporation Executive Savings Plan I & II (as Amended and Restated effective January 1, 2003) (the "Plan") is amended, effective as of December 19, 2006, as follows:

1 Article VI of the Plan is hereby amended by adding the following new Section 6 8 at the end thereof:

"6 8 *Adjustments to Duke Energy Common Stock—Stock Deferrals Subaccount and Duke Energy Common Stock Fund* Each phantom unit of Duke Energy Corporation common stock credited to the Duke Energy Common Stock—Stock Deferrals Subaccount and Duke Energy Common Stock Fund on behalf of a Participant on the Distribution Date shall be converted, as of the Distribution Date, into phantom units of Spectra Energy Corp common stock and phantom units of Duke Energy Corporation common stock and reallocated as follows:

(a) The number of phantom units of Spectra Energy Corp common stock shall be equal to the number of shares of Spectra Energy Corp common stock to which the Participant would have been entitled on the Distribution had the phantom units of Duke Energy Corporation common stock represented actual shares of Duke Energy Corporation as of the Record Date, the resulting number of phantom units of Spectra Energy Corp common stock being rounded down to the nearest whole unit

(b) The resulting number of phantom units of Spectra Energy Corp common stock shall automatically be transferred from the Duke Energy Common Stock—Stock Deferrals Subaccount and Duke Energy Common Stock Fund and credited to the RSP Investment Option that invests primarily in Spectra Energy Corp common stock (the "Spectra Common Stock Fund"), effective as of the Distribution Date

(c) A Participant may elect, pursuant to rules and procedures prescribed by the Company, to reallocate amounts deemed invested in the Spectra Common Stock Fund into any other open investment option. The Spectra Common Stock Fund shall be closed to additional deferrals and to transfers from any other investment option.

(d) Capitalized terms used in this Section 6 8 that are not defined in this Plan shall have the meaning set forth in the Employee Matters Agreement by and between Duke Energy Corporation and Spectra Energy Corp "

2 Article XIV of the Plan is hereby amended by adding the following new Section 14 5 at the end thereof:

"14 5 *Transfer of Accounts* The Account of each Spectra Energy Participant maintained under the Plan immediately prior to the Distribution Date shall be transferred to the Spectra Energy Corp Executive Savings Plan and assumed by Spectra Energy Corp as of the Distribution Date (the "Assumed Amounts"). For purposes of this Plan, the term "Assumed Amounts" shall include any amounts of Base Pay or Incentive Plan awards of a Spectra Energy Participant that are earned but not yet paid as of the Distribution Date or equity awards granted to a Spectra Energy Participant under the Duke Energy Corporation 1998 Long-Term Incentive Plan, that were properly deferred by the Spectra Energy Participant under the Plan but that had not yet been credited to his or her Account under the Plan as of the Distribution Date Each such Spectra Energy Participant shall have no further rights under the Plan immediately after his or her Account is transferred to the Spectra Energy Corp Executive Savings Plan and assumed by Spectra Energy Corp in accordance with the terms and conditions of the Employee Matters Agreement by and between Duke Energy Corporation and Spectra Energy Corp (the "Employee Matters Agreement") Capitalized terms used in this Section 14 5 that are not defined in this Plan shall have the meaning set forth in the Employee Matters Agreement "

3. Except as explicitly set forth herein, the Plan will remain in full force and effect

This amendment has been executed by an authorized officer of Duke Energy Corporation on December 19, 2006

DUKE ENERGY CORPORATION

By: /S/ CHRISTOPHER C. ROLFE

Christopher C Rolfe
Group Executive and
Chief Administrative Officer

Exhibit 10.18.5

AMENDMENT TO
DUKE ENERGY CORPORATION
EXECUTIVE CASH BALANCE PLAN

The Duke Energy Corporation Executive Cash Balance Plan (the "Plan") is amended, effective as of December 1, 2006, as follows:

1 Section 2 16 of the Duke Energy Corporation Executive Cash Balance Plan I is hereby superseded and replaced in its entirety as set forth below:

"2 16 "Retirement Cash Balance Plan" means the Duke Energy Retirement Cash Balance Plan as in effect on October 3, 2004, without giving effect to amendments adopted thereafter "

2 The last sentence of Section 4 4 of the Duke Energy Corporation Executive Cash Balance Plan II is hereby deleted in its entirety

3 The first two sentences of Section 6 1 of the Duke Energy Corporation Executive Cash Balance Plan II are hereby deleted and replaced in their entirety with the following:

"A Participant whose Company employment terminates on or after December 31, 2006 will receive, or will begin to receive, payment of his vested Make Whole Account and his vested Supplemental Account, if any, as soon as administratively feasible following the month in which the Participant's employment terminates "

4. Except as explicitly set forth herein, the Plan will remain in full force and effect

This amendment has been approved and signed by an authorized officer of Duke Energy Corporation as of the date specified above

DUKE ENERGY CORPORATION

By: /S/ CHRISTOPHER C. ROLFE

Christopher C Rolfe
Group Executive and Chief
Administrative Officer

Exhibit 10.18.6

AMENDMENT TO
DUKE ENERGY CORPORATION EXECUTIVE CASH BALANCE PLAN I & II
(As Amended and Restated effective January 1, 1999)

The Duke Energy Corporation Executive Cash Balance Plan I & II (As Amended and Restated effective January 1, 1999) (the "Plan") is amended, effective as of December 31, 2006, as follows:

1 Article 12 of the Plan is hereby amended by adding the following new Section 12.5 at the end thereof:

"12.5 *Transfer of Accounts* The Make-Whole Account and Supplemental Account, if any, of each Spectra Energy Participant maintained under the Plan immediately prior to the Distribution Date shall be transferred to the Spectra Energy Corp Executive Cash Balance Plan and assumed by Spectra Energy Corp as of the Distribution Date Each such Spectra Energy Participant shall have no further rights under the Plan immediately after his or her Make-Whole Account and Supplemental Account, if any, are transferred to the Spectra Energy Corp Executive Cash Balance Plan and assumed by Spectra Energy Corp in accordance with the terms and conditions of the Employee Matters Agreement by and between Duke Energy Corporation and Spectra Energy Corp (the "Employee Matters Agreement") Capitalized terms used in this Section 12.5 that are not defined in this Plan shall have the meaning set forth in the Employee Matters Agreement"

2 Except as explicitly set forth herein, the Plan will remain in full force and effect

This amendment has been executed by an authorized officer of Duke Energy Corporation on December 19, 2006

DUKE ENERGY CORPORATION

By: /S/ CHRISTOPHER C. ROLFE

Christopher C. Rolfe
Group Executive and
Chief Administrative Officer

Exhibit 10.19.1

AMENDMENT TO
DUKE ENERGY CORPORATION RETIREMENT BENEFIT EQUALIZATION PLAN
(effective January 1, 1999)

The Duke Energy Corporation Retirement Benefit Equalization Plan (effective January 1, 1999) (the "Plan") is amended, effective as of December 21, 2006, as follows:

1 The Plan is hereby amended by adding the following new Section 13 at the end thereof:

"13 *Termination of Plan.* Effective as of December 31, 2006, the Plan is hereby frozen such that no further benefits or entitlements shall accrue thereunder "

This amendment has been approved and signed by an authorized officer of Duke Energy Corporation as of the date specified above

DUKE ENERGY CORPORATION

By: /S/ CHRISTOPHER C. ROLFE

Christopher C Rolfe
Group Executive and
Chief Administrative Officer

Exhibit 10.63

AMENDMENT TO
DUKE ENERGY CORPORATION DIRECTORS' SAVINGS PLAN I & II
(as Amended and Restated effective February 24, 2004)

The Duke Energy Corporation Directors' Savings Plan I & II (as Amended and Restated effective February 24, 2004) (the "Plan") is amended, effective as of December 19, 2006, as follows:

1 Article IV of the Plan is hereby amended by adding the following new Section 4 5 at the end thereof:

"4 5 Each phantom unit of Company common stock credited to the DECS Investment Option and the Stock Deferral Investment Option on behalf of a Participant on the Distribution Date shall be converted, as of the Distribution Date, into phantom units of Company common stock and phantom units of Spectra Energy Corp common stock and reallocated as follows:

(i) The number of phantom units of Spectra Energy Corp common stock shall be equal to the number of shares of Spectra Energy Corp common stock to which the Participant would have been entitled on the Distribution had the phantom units of Company common stock represented actual shares of the Company as of the Record Date, the resulting number of phantom units of Spectra Energy Corp common stock being rounded down to the nearest whole unit

(ii) The resulting number of phantom units of Spectra Energy Corp common stock shall automatically be transferred from the DECS Investment Option and the Stock Deferral Investment Option and credited to the Plan's investment option that corresponds to the RSP's Spectra Energy Corp Common Stock Fund (the "SECS Investment Option")

(iii) A Participant (or, if the Participant is dead, the Participant's beneficiary) may elect, pursuant to rules and procedures prescribed by the Company, to reallocate amounts deemed invested in Spectra Energy Corp common stock under the SECS Investment Option to any other open investment option The SECS Investment Option shall be closed to additional deferrals and to transfers from any other investment option

(iv) Capitalized terms used in this Section 4.5 that are not defined in this Plan shall have the meaning set forth in the Employee Matters Agreement by and between Duke Energy Corporation and Spectra Energy Corp "

2 Article XI of the Plan is hereby amended by adding the following new Section 11 5 at the end thereof:

"11 5 The Account of each member of the Board of Directors of Spectra Energy Corp or its predecessor companies (a "Spectra Energy Participant") maintained under the Plan immediately prior to the Distribution Date shall be transferred to the Spectra Energy Corp Directors' Savings Plan and assumed by Spectra Energy Corp as of the Distribution Date (the "Assumed Amounts") For purposes of this Plan, the term "Assumed Amounts" shall include any amount of Compensation of a Spectra Energy Participant that is earned but not yet paid as of the Distribution Date and Phantom Stock Units granted to a Spectra Energy Participant under the Duke Energy Corporation 1998 Long-Term Incentive Plan, that were properly deferred by a Spectra Energy Participant under the Plan but that had not yet been credited to his or her Account under the Plan as of the Distribution Date Each such Spectra Energy Participant shall have no further rights under the Plan immediately after his or her Account is transferred to the Spectra Energy Corp Directors' Savings Plan and assumed by Spectra Energy Corp in accordance with the terms and conditions of the Employee Matters Agreement by and between Duke Energy Corporation and Spectra Energy Corp (the "Employee Matters Agreement") Capitalized terms used in this Section 11.5 that are not defined in this Plan shall have the meaning set forth in the Employee Matters Agreement "

3 Except as explicitly set forth herein, the Plan will remain in full force and effect

This amendment has been executed by an authorized officer of Duke Energy Corporation on December 19, 2006

DUKE ENERGY CORPORATION

By: /S/ CHRISTOPHER C. ROLFE

Christopher C Rolfe
Group Executive and
Chief Administrative Officer

EXHIBIT 10.64

AMENDMENT TO THE CINERGY CORP. EXCESS PENSION PLAN

The Cinergy Corp Excess Pension Plan, as amended and restated effective as of January 1, 1998, and as amended from time to time (the "Plan"), is hereby amended effective as of January 1, 2007

(1) Explanation of Amendment

The Plan is amended to clarify the relationship between the Plan and the Cinergy Corp Non-Union Employees' Pension Plan ("Cinergy's Pension Plan") in light of the adoption of the Duke Energy cash balance formula under Cinergy's Pension Plan

(2) Amendment

Section 5 3 of the Plan is hereby amended in its entirety to read as follows:

"5 3 *Cash Balance Death Benefit*

The following rules shall apply upon the death of a Participant who is classified as a "Cash Balance Participant" or "Duke Account Participant" under Cinergy's Pension Plan:

(a) *Spouse Beneficiary* If a death benefit is payable under Article 6 of Cinergy's Pension Plan or Article GV of Addendum G of Cinergy's Pension Plan on account of the Participant's death and the Participant's Beneficiary (as defined in Cinergy's Pension Plan) at the date of the Participant's death is his Spouse, such Spouse shall receive a death benefit in an amount equal to the Actuarial Equivalent (as defined in Cinergy's Pension Plan) of the benefits that would otherwise have been payable to the Participant under the Plan The form of the death benefit payable to the Spouse under the Plan shall be the same form in which the Spouse's benefit is payable under Cinergy's Pension Plan. The payment of the Spouse's death benefit under the Plan shall be made, or shall commence, as of the same date as the Spouse's benefit under Cinergy's Pension Plan is made or commences

(b) *Non-Spouse Beneficiary* If a death benefit is payable under Article 6 of Cinergy's Pension Plan or under Article GV of Addendum G of Cinergy's Pension Plan on account of the Participant's death and the Participant's Beneficiary (as defined in Cinergy's Pension Plan) at the date of the Participant's death is any person other than the Participant's Spouse, such Beneficiary shall receive a death benefit in an amount equal to the Actuarial Equivalent (as defined in Cinergy's Pension Plan) of the benefits that would otherwise have been payable to the Participant under the Plan The death benefit shall be payable in the form of a single lump sum cash payment and shall be made as soon as administratively practicable following the Participant's death "

IN WITNESS WHEREOF, Cinergy Corp has caused this Amendment to be executed effective as of the date set forth herein

By: /S/ CHRISTOPHER C. ROLFE

Christopher C Rolfe
Group Executive and
Chief Administrative Officer

Exhibit 10.65

AMENDMENT TO
CINERGY CORP. 401(K) EXCESS PLAN

The Cinergy Corp 401(k) Excess Plan (the "Plan") is amended, effective as of December 18, 2006, as follows:

1 Section 2 1 of the Plan is hereby amended by adding the following at the end thereof

"(ff) "Duke Energy Common Stock—Stock Deferrals Account" means, with respect to a Participant, the bookkeeping account established and maintained pursuant to Section 3 2(e)(iv)

(gg) "Duke Formula Employee" has the meaning given to such term in the 401(k) Plan

Capitalized terms that are not defined in Article II shall have the meaning set forth in the Company's 2006 Long-Term Incentive Plan "

2 Section 3 2 of the Plan is hereby amended by adding the following new subsections (e) and (f) at the end thereof:

"(e) *Deferrals of Stock Awards* Each eligible Participant may irrevocably elect to defer, in accordance with the terms of this Plan, the entire amount of any nonvested Award granted under a long-term incentive plan sponsored by the Company (including the Company's 2006 Long-Term Incentive Plan), subject to the following conditions:

(i) Except as otherwise provided in this Section, the deferral election shall be made by, and shall become irrevocable as of, December 31 (or such earlier date as specified by the Committee) of the calendar year next preceding the calendar year for which such Award is granted, or at such later time as is permitted by the Committee, consistent with Section 409A of the Code, during the calendar year in which a Participant initially becomes eligible for the Plan

(ii) To the extent permitted by the Committee, and except as otherwise provided in Section 3 2(e)(iii), with respect to an Award that is subject to a forfeiture condition requiring the Participant's continued services for a period of at least thirteen (13) months from the date that the service provider obtains a "legally binding right" to such Award (within the meaning of Section 409A of the Code), the deferral election shall be made by, and shall become irrevocable as of, the thirtieth (30th) day following the date that the Participant obtains the legally binding right to such Award.

(iii) To the extent permitted by the Committee, with respect to an Award that constitutes "performance-based compensation" (within the meaning of Section 409A of the Code), the deferral election shall be made by, and shall become irrevocable as of, the date that is 6 months before the end of the applicable performance period (or such earlier date as specified by the Committee), provided that in no event may such deferral election be made after such Award has become both substantially certain to be paid and readily ascertainable (within the meaning of Section 409A of the Code)

(iv) Upon the date that an Award that the Participant has elected to defer would otherwise have been payable, the number of shares of stock or the cash payment that would have become so payable but for the deferral election shall be converted into an equal number of units in the Duke Energy Common Stock—Stock Deferrals Account

(v) Dividend Equivalents, to the extent deferred, shall also be credited to the Participant's Duke Energy Common Stock—Stock Deferrals Account commencing on the payment date of the first cash dividend of Company Stock that is declared after the date on which the deferred Award vests

(vi) No deferral of a stock option or restricted stock award shall be permissible

(f) *Dividend Equivalents Deferrals* Each eligible Participant may irrevocably elect to defer, in accordance with the terms of this Plan, 100% of the amounts that would otherwise become payable as Dividend Equivalents, with respect to (i) an Award that is designated in the Award Agreement as a "Chairman's Award," or (ii) an Award with respect to which the Award Agreement specifically provides for the deferral of Dividend Equivalents Such election must be made by the Participant at the time the Participant elects to defer receipt of the related Award pursuant to the terms of Section 3 2(e) Dividend Equivalents that have been deferred pursuant to the first sentence of this Section and credited to the Participant's Account shall be credited to the Participant's Duke Energy Common Stock—Stock Deferrals Account as of the dates such amounts would otherwise become payable pursuant to such award "

3 Section 3 3 of the Plan is hereby superseded and replaced in its entirety as set forth below:

"3 3 *Employer Base Matching Contributions*

(a) If an Eligible Employee other than a Duke Formula Employee is entitled to a "Base Matching Contribution" under his or her 401(k) Plan, the Employer shall make an Employer Base Matching Contribution to the Participant's Matching Account equal to the amount of the Participant's "Base Matching Contribution" computed in accordance with the 401(k) Plan (prior to the limitation of Code Paragraph 401(m)(2)), but using the Participant's Compensation as defined in this Plan

(b) If an Eligible Employee that is also a Duke Formula Employee is entitled to a "Base Matching Contribution" under his or her 401(k) Plan, the Employer shall make an Employer Base Matching Contribution to the Participant's Matching Account equal to the amount, if any, by which the lesser of the amounts in subparagraph (i) or (ii) below, exceeds the amount in subparagraph (iii) below:

(i) The maximum matching contribution the Participant was eligible to receive for the Plan Year under the 401(k) Plan based upon the Participant's "Compensation" as defined in the 401(k) Plan for the Plan Year, but determined without regard to the limitations of Code Paragraph 401(a)(17) and any deferral of Compensation pursuant to Section 3 2 of this Plan or bonuses pursuant to the Cinergy Corp Nonqualified Deferred Incentive Compensation Plan

(ii) The Participant's "Deferred Compensation Contribution" as defined under the 401(k) Plan for the Plan Year, plus the Participant's deferral of Compensation pursuant to Section 3 2 of this Plan or deferral of bonus pursuant to the Cinergy Corp Nonqualified Deferred Incentive Compensation Plan during the Plan Year.

(iii) The "Base Matching Contribution" credited to the Participant's account under the 401(k) Plan for the Plan Year

(c) If the Participant becomes a Duke Formula Employee during a Plan Year, the Committee shall prorate the amount of his or her Base Matching Contribution for the Plan Year based on the preceding provisions of this Section "

4 Section 3.5 of the Plan is hereby amended by inserting the words "a Duke Energy Common Stock—Stock Deferrals Account," immediately after the phrase "a Deferral Account,"

5 Section 4 1 of the Plan is hereby amended by inserting the words "Duke Energy Common Stock—Stock Deferrals Account," immediately after the phrase "Deferral Account,"

6 Section 4 2(a) of the Plan is hereby amended by adding the following sentence at the end thereof

"The amounts in the Duke Energy Common Stock—Stock Deferrals Account shall be credited and maintained as units of a phantom investment that mirror the performance of Company Stock (with cash dividends reinvested) "

7 Section 4 2(b) of the Plan is hereby amended by adding the following sentence at the end thereof:

"Notwithstanding anything contained herein to the contrary, no transfers may be made into or out of the Duke Energy Common Stock—Stock Deferrals Account "

8 Section 4.2 of the Plan is hereby amended by adding the following new subsection (d) at the end thereof:

"(d) If there shall occur any merger, consolidation, liquidation, issuance of rights or warrants to purchase securities, recapitalization, reclassification, stock dividend, spin-off, split-off, stock split, reverse stock split or other distribution with respect to the shares of Company Stock, or any similar corporate transaction or event in respect of such shares, then the Committee shall, in the manner and to the extent that it deems appropriate and equitable to the Participants and consistent with the terms of this Plan, cause a proportionate adjustment to be made in number and kind of phantom investment units of shares of Company Stock deemed held under the Plan Moreover, in the event of any such transaction or event, the Committee, in its discretion, may provide in substitution for any or all phantom investment units of shares of Company Stock such alternative consideration as it, in good faith, may determine to be equitable under the circumstances "

9 Section 4.3(b) of the Plan is hereby superseded and replaced in its entirety as set forth below

"(b) The Employer Base Matching Contribution under Section 3 3 of this Plan shall be credited to a Participant's Matching Account in terms of cash as of the last day of each Plan Year An Eligible Employee does not need to make deferrals pursuant to Section 3 2 (Election to Defer) of this Plan to receive Employer Base Matching Contributions "

10 Section 4 3(c) of the Plan is hereby amended by inserting the words "Duke Energy Common Stock—Stock Deferrals Account," immediately after the phrase "Deferral Account,"

11 The second sentence of Section 4 4(a) of the Plan is hereby amended by inserting the words "Duke Energy Common Stock—Stock Deferrals Accounts," immediately after the phrase "Deferral Accounts,"

12 Section 5 1(d) of the Plan is hereby amended by adding the following new subparagraph (4) at the end thereof:

"(4) Amounts credited as units to each Participant's Duke Energy Common Stock—Stock Deferrals Account shall be converted to and distributed in the form of whole shares of Company Stock and cash for any fractional share To the extent that the delivery of any shares of Company Stock to a Participant under this Section 5 1(d)(4) otherwise would cause all or any portion of the Plan to be considered an "equity compensation plan" as such term is defined in Section 303A(8) of the New York Stock Exchange Listed Company Manual or any successor rule ("Listed Company Manual"), then such shares shall be paid from, and shall count against the share reserve of, a Company-sponsored "equity compensation plan" designated by the Committee that complies with the shareholder approval requirements contained in the Listed Company Manual "

13 Except as explicitly set forth herein, the Plan will remain in full force and effect

This amendment has been approved and signed by an authorized officer of Duke Energy Corporation as of the date specified above

DUKE ENERGY CORPORATION

By: /S/ CHRISTOPHER C. ROLFE

Christopher C. Rolfe
Group Executive and Chief
Administrative Officer

Exhibit 10.66

AMENDMENT TO
CINERGY CORP. EXCESS PROFIT SHARING PLAN

The Cinergy Corp Excess Profit Sharing Plan (the "Plan") is amended, effective as of December 19, 2006, as follows:

1 Section 4 2 of the Plan is hereby amended by adding the following new paragraph (d) at the end thereof:

"(d) Notwithstanding anything contained herein to the contrary, each phantom unit of Duke Energy Corporation common stock (held in the account formerly known as the Cinergy Corp Common Stock Fund, which has been renamed the Duke Energy Common Stock Fund) credited to a Participant's Account on the Distribution Date shall be converted, as of the Distribution Date, into phantom units of Spectra Energy Corp common stock and phantom units of Duke Energy Corporation common stock and reallocated as follows:

(1) The number of phantom units of Spectra Energy Corp common stock shall be equal to the number of shares of Spectra Energy Corp common stock to which the Participant would have been entitled on the Distribution had the phantom units of Duke Energy Corporation common stock represented actual shares of Duke Energy Corporation common stock as of the Record Date, the resulting number of phantom units of Spectra Energy Corp common stock being rounded down to the nearest whole unit

(2) The resulting number of phantom units of Spectra Energy Corp common stock shall automatically be transferred from the Duke Energy Corporation Common Stock Fund and credited to a separate Investment Option that corresponds to the performance of Spectra Energy Corp common stock (the "Spectra Investment Option"), effective as of the Distribution Date

(3) A Participant may elect, pursuant to rules and procedures prescribed by the Committee, to reallocate amounts deemed invested in the Spectra Investment Option into any other open Investment Option The Spectra Investment Option shall be closed to additional deferrals and to transfers from any other Investment Option

(4) Capitalized terms used in this Section 4 2(d) that are not defined in this Plan shall have the meaning set forth in the Employee Matters Agreement by and between Duke Energy Corporation and Spectra Energy Corp."

2 Except as explicitly set forth herein, the Plan will remain in full force and effect

IN WITNESS WHEREOF, Cinergy Corp has caused this Amendment to be executed and approved effective as of the date set forth herein

By: /S/ CHRISTOPHER C. ROLFE

Christopher C Rolfe
Group Executive and Chief
Administrative Officer

Date: 12/19/06

Exhibit 10.67

AMENDMENT TO
CINERGY CORP. 401(K) EXCESS PLAN

The Cinergy Corp 401(k) Excess Plan (the "Plan") is amended, effective as of December 19, 2006, as follows:

1. Section 4.2 of the Plan is hereby amended by adding the following new paragraph (c) at the end thereof:

   "(c) Notwithstanding anything contained herein to the contrary, each phantom unit of Company Stock credited to a Participant's Account on the Distribution Date shall be converted, as of the Distribution Date, into phantom units of Spectra Energy Corp common stock and phantom units of Company Stock and reallocated as follows:

   (1) The number of phantom units of Spectra Energy Corp common stock shall be equal to the number of shares of Spectra Energy Corp common stock to which the Participant would have been entitled on the Distribution had the phantom units of Company Stock represented actual shares of the Company as of the Record Date, the resulting number of phantom units of Spectra Energy Corp common stock being rounded down to the nearest whole unit

   (2) The resulting number of phantom units of Spectra Energy Corp common stock shall automatically be transferred from the Company Stock Investment Option and credited to a separate Investment Option that corresponds to the performance of Spectra Energy Corp common stock (the "Spectra Investment Option"), effective as of the Distribution Date

   (3) A Participant may elect, pursuant to rules and procedures prescribed by the Company, to reallocate amounts deemed invested in the Spectra Investment Option into any other open Investment Option The Spectra Investment Option shall be closed to additional deferrals and to transfers from any other Investment Option

   (4) Capitalized terms used in this Section 4 2(c) that are not defined in this Plan shall have the meaning set forth in the Employee Matters Agreement by and between Duke Energy Corporation and Spectra Energy Corp "

2. Section 5 1(d) of the Plan is hereby amended by adding the following new sub-paragraph (3) at the end thereof:

   "(3) *Spectra Energy Corp Common Stock* The portion of a Participant's Account that is deemed invested in Spectra Energy Corp common stock at the time of distribution will be distributed in the form of cash in accordance with rules and procedures prescribed by the Company "

3. Except as explicitly set forth herein, the Plan will remain in full force and effect

IN WITNESS WHEREOF, Cinergy Corp has caused this Amendment to be executed and approved effective as of the date set forth herein.

By: /S/ CHRISTOPHER C. ROLFE

Christopher C Rolfe
Group Executive and Chief
Administrative Officer

Date: 12/19/06

Exhibit 10.68

AMENDMENT TO
CINERGY CORP. DIRECTORS' DEFERRED COMPENSATION PLAN

The Cinergy Corp Directors' Deferred Compensation Plan (the "Plan") is amended, effective as of December 19, 2006, as follows:

1 Section 4 3 of the Plan is hereby amended by adding the following new paragraph at the end thereof

"Notwithstanding anything contained herein to the contrary, each phantom unit of Common Stock credited to a Participant's Unit Account on the Distribution Date shall be converted, as of the Distribution Date, into phantom units of Spectra Energy Corp common stock and phantom units of Common Stock and reallocated as follows:

(a) The number of phantom units of Spectra Energy Corp common stock shall be equal to the number of shares of Spectra Energy Corp common stock to which the Participant would have been entitled on the Distribution had the phantom units of Common Stock represented actual shares of Duke Energy Corporation as of the Record Date, the resulting number of phantom units of Spectra Energy Corp common stock being rounded down to the nearest whole unit

(b) The resulting number of phantom units of Spectra Energy Corp common stock shall automatically be transferred from the Unit Account and credited to a separate individual account established and maintained for the exclusive purpose of accounting for the Participant's deferred amounts which is accrued in terms of a theoretical number of units of Spectra Energy Corp common stock (the "Spectra Unit Account"), effective as of the Distribution Date The Spectra Unit Account shall thereafter be subject to the same adjustment provisions related to cash dividends and changes in Spectra Energy Corp common stock as apply to the Unit Account in Section 4 3 hereof

(c) A Participant may elect, pursuant to rules and procedures prescribed by Duke Energy Corporation, to reallocate amounts deemed invested in the Spectra Unit Account into the Unit Account or the Deferred Compensation Account The Spectra Unit Account shall be closed to additional deferrals and to transfers from any other deemed investment option

(d) Capitalized terms used in this Section 4 3 that are not defined in this Plan shall have the meaning set forth in the Employee Matters Agreement by and between Duke Energy Corporation and Spectra Energy Corp."

2 Article 6 of the Plan is hereby amended by adding the following new Section 6 4 at the end thereof:

"6 4 *Payment of Deferred Fees Credited to the Spectra Unit Account* Notwithstanding anything contained in this Article 6 or Article 8 to the contrary, the amounts credited to a Participant's Spectra Unit Account will be distributed in the form of cash "

3 Except as explicitly set forth herein, the Plan will remain in full force and effect

IN WITNESS WHEREOF, Cinergy Corp has caused this Amendment to be executed and approved effective as of the date set forth herein

By: /S/ CHRISTOPHER C. ROLFE

Christopher C Rolfe
Group Executive and Chief
Administrative Officer

Date: 12/19/06

Exhibit 12

COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES

The ratio of earnings to fixed charges is calculated using the Securities and Exchange Commission guidelines[(a)]

	Year Ended December 31,				
	2006	2005	2004	2003	2002
	(dollars in millions)				
Earnings as defined for fixed charges calculation					
Add:					
Pretax (loss) income from continuing operations[(b)(e)]	$ 2,192	$ 3,869	$ 1,792	$ (307)	$ 1,526
Fixed charges	1,382	1,159	1,433	1,620	1,550
Distributed income of equity investees	893	473	140	263	369
Deduct:					
Preference security dividend requirements of consolidated subsidiaries	27	27	31	139	170
Interest capitalized[(c)]	56	23	18	58	193
Total earnings (as defined for the Fixed Charges calculation)	$ 4,384	$ 5,451	$ 3,316	$ 1,379	$ 3,082
Fixed charges:					
Interest on debt, including capitalized portions	$ 1,311	$ 1,096	$ 1,365	$ 1,441	$ 1,340
Estimate of interest within rental expense	44	36	37	40	40
Preference security dividend requirements of consolidated subsidiaries	27	27	31	139	170
Total fixed charges	$ 1,382	$ 1,159	$ 1,433	$ 1,620	$ 1,550
Ratio of earnings to fixed charges[(e)]	3.2	4.7	2.3	(d)	2.0

(a) Certain prior year Income Statement amounts above have been adjusted for businesses reclassified to discontinued operations during 2006

(b) Excludes minority interest expenses and income or loss from equity investees

(c) Excludes equity costs related to Allowance for Funds Used During Construction that are included in Other Income and Expenses in the Consolidated Statements of Operations

(d) Earnings were inadequate to cover fixed charges by $241 million for the year ended December 31, 2003

(e) Includes pre-tax gains on the sale of TEPPCO GP and LP of approximately $0 9 billion, net of minority interest, in 2005

EXHIBIT 21

LIST OF SUBSIDIARIES

The following is a list of certain subsidiaries (greater than 50% owned) of the registrant and their respective states or countries of incorporation:

1388368 Ontario Inc (Ontario)
3036243 Nova Scotia Company (Canada—Nova Scotia)
Advance SC LLC (South Carolina)
Aguaytia Energy del Peru S R Ltda (Peru)
Aguaytia Energy, LLC
Antelope Ridge Gas Processing Plant
Attiki Denmark ApS (Denmark)
Bison Insurance Company Limited (Bermuda)
Brown County Landfill Gas Associates, L P (Delaware)
Brownsville Power I, LLC (Delaware)
BSPE General, LLC (Texas)
BSPE Holdings, LLC (Delaware)
BSPE Limited, LLC (Delaware)
BSPE, L P (Delaware)
Cadence Network, Inc (Delaware)
Caldwell Power Company (North Carolina)
Catawba Manufacturing and Electric Power Company (North Carolina)
Centra Gas Toluca S De R L De D V (Mexico)
CGP Global Greece Holdings, SA (Greece)
Cinergy Capital & Trading, Inc (Indiana)
Cinergy Climate Change Investments, LLC (Delaware)
Cinergy Corp (Delaware)
Cinergy General Holdings, LLC (Delaware)
Cinergy Global (Cayman) Holdings, Inc (Cayman Islands)
Cinergy Global Ely, Inc (Delaware)
Cinergy Global Hellas S A (Greece)
Cinergy Global Holdings, Inc (Delaware)
Cinergy Global Power (UK) Limited (England)
Cinergy Global Power Africa (Proprietary) Limited (South Africa)
Cinergy Global Power Iberia, S A (Spain)
Cinergy Global Power Services Limited (London, England)
Cinergy Global Power, Inc (Delaware)
Cinergy Global Resources, Inc (Delaware)
Cinergy Global Trading Limited (England)
Cinergy Global Tsavo Power (Cayman Islands)
Cinergy Holdings BV (Netherlands)
Cinergy Investments, Inc (Delaware)
Cinergy Limited Holdings, LLC (Delaware)
Cinergy Mexico General, LLC (Delaware)
Cinergy Mexico Holdings, LP (Delaware)
Cinergy Mexico Limited, LLC (Delaware)
Cinergy Mexico Marketing & Trading, LLC (Delaware)
Cinergy Origination & Trade, LLC (Delaware)
Cinergy Power Generation Services, LLC (Delaware)
Cinergy Power Investments, Inc (Ohio)
Cinergy Receivables Company LLC (Delaware)
Cinergy Retail Power General, Inc (Texas)
Cinergy Retail Power Limited, Inc (Delaware)
Cinergy Retail Power, L P (Delaware)
Cinergy Risk Solutions Ltd (Vermont)
Cinergy Solutions—Utility, Inc (Delaware)
Cinergy Solutions Limited Partnership (Ontario)
Cinergy Solutions Partners, LLC (Delaware)
Cinergy Technology, Inc (Indiana)
Cinergy Two, Inc (Delaware)
Cinergy UK, Inc (Delaware)
Cinergy Wholesale Energy, Inc (Ohio)
Cinergy-Centrus Communications, Inc (Delaware)
Cinergy-Centrus, Inc (Delaware)
CinFuel Resources, Inc (Delaware)
CinPower I, LLC (Delaware)
Claiborne Energy Services, Inc (Louisiana)
Comercializadora Duke Energy de Centro America, Limitada (Guatemala)
Commercial Electricity Supplies Limited (England)
Compania de Servicios de Compresion de Campeche, S A de C V (Mexico)
Countryside Landfill Gasco, LLC (Delaware)
CRE, LLC (Delaware)
CSCC Holdings Limited Partnership (Canada—British Columbia)
CSGP General, LLC (Texas)
CSGP Limited, LLC (Delaware)
CSGP of Southeast Texas, LLC (Delaware)
CSGP Services, L P (Delaware)
CST General, LLC (Texas)
CST Green Power, L P (Delaware)
CST Limited, LLC (Delaware)
CTE Petrochemicals Company (Cayman Islands)
D/FD Foreign Sales Corporation (Barbados)
D/FD Holdings, LLC (Delaware)
D/FD International Services Brasil Ltda (Brazil)
D/FD Operating Services LLC (Delaware)
DE Fossil-Hydro Engineering, Inc (North Carolina)
DE Marketing Canada Ltd (Canadian Federal)

DE Nuclear Engineering, Inc (North Carolina)
DE Operating Services, LLC (Delaware)
DE Power Generating, LLC (Delaware)
DEGS Biogas, Inc (Delaware)
DEGS EPCOM College Park, LLC (Delaware)
DEGS GASCO, LLC (Delaware)
DEGS O&M, LLC (Delaware)
DEGS of Boca Raton, LLC (Delaware)
DEGS of Cincinnati, LLC (Ohio)
DEGS of Delta Township, LLC (Delaware)
DEGS of Lansing, LLC (Delaware)
DEGS of Monaca, LLC (Delaware)
DEGS of Narrows, LLC (Delaware)
DEGS of Oklahoma, LLC (Delaware)
DEGS of Parlin, LLC (Delaware)
DEGS of Philadelphia, LLC (Delaware)
DEGS of Rock Hill, LLC (Delaware)
DEGS of San Diego, Inc (Delaware)
DEGS of Shreveport, LLC (Delaware)
DEGS of South Charleston, LLC (Delaware)
DEGS of St Bernard, LLC (Delaware)
DEGS of St Paul, LLC (Delaware)
DEGS of Tuscola, Inc (Delaware)
Delta Township Utilities, LLC (Delaware)
DENA Asset Partners, L P (Delaware)
DENA Partners Holding, LLC (Delaware)
DETM Marketing Northeast, LLC (Delaware)
DETMI Management, Inc (Colorado)
Dixilyn-Field (Nigeria) Limited (Nigeria)
Dixilyn-Field Drilling Company (Delaware)
Dixilyn-Field International Drilling Company, S A (Panama)
DTMSI Management Ltd (Alberta, Canada)
Duke Broadband, LLC (Delaware)
Duke Canada Ltd (Alberta, Canada)
Duke Capital Partners, LLC (Delaware)
Duke Communication Services Caribbean Ltd (Bermuda)
Duke Communication Services, Inc (North Carolina)
Duke Communications Holdings, Inc (Delaware)
Duke Energy Allowance Management, LLC (Delaware)
Duke Energy Americas, LLC (Delaware)
Duke Energy Business Services LLC (Delaware)
Duke Energy Carolinas Plant Operations, LLC (Delaware)
Duke Energy Carolinas, LLC (North Carolina)
Duke Energy Development Pty Ltd (Australia)
Duke Energy Egenor S en C por A (Peru)
Duke Energy Electroquil Partners (Delaware)
Duke Energy Engineering, Inc (Ohio)
Duke Energy Finance Canada Limited Partnership (Canada—Alberta)
Duke Energy Fossil-Hydro California, Inc (Delaware)
Duke Energy Fossil-Hydro, LLC (Delaware)
Duke Energy Generating S A (Argentina)
Duke Energy Generation Services Holding Company, Inc (Delaware)
Duke Energy Generation Services, Inc (Delaware)
Duke Energy Global Markets, Inc (Nevada)
Duke Energy Greenleaf, LLC (Delaware)
Duke Energy Group Holdings, LLC (Delaware)
Duke Energy Group, LLC (Delaware)
Duke Energy Hydrocarbons Canada Limited Partnership (Canada)
Duke Energy Hydrocarbons Investments Ltd. (Canada—Alberta)
Duke Energy Indiana, Inc (Indiana)
Duke Energy Industrial Sales, LLC (Delaware)
Duke Energy Interamerican Holding Company LDC (Cayman Islands)
Duke Energy International (Europe) Holdings ApS (Denmark)
Duke Energy International (Europe) Limited (United Kingdom)
Duke Energy International Argentina Holdings (Cayman Islands)
Duke Energy International Argentina Marketing/Trading (Bermuda) Ltd (Bermuda)
Duke Energy International Asia Pacific Ltd (Bermuda)
Duke Energy International Bolivia Holdings No 1, LLC (Delaware)
Duke Energy International Bolivia Investments No 1 Limited (Cayman Islands)
Duke Energy International Bolivia Investments No 2 Limited (Cayman Islands)
Duke Energy International Brasil Commercial, Ltda (Brazil)
Duke Energy International Brasil Holdings, LLC (Delaware)
Duke Energy International Brazil Holdings Ltd (Bermuda)
Duke Energy International del Ecuador Cia Ltda (Ecuador)
Duke Energy International El Salvador Comercializadora de El Salvador, S A de C V (El Salvador)
Duke Energy International El Salvador Investments No 1 Ltd (Bermuda)
Duke Energy International El Salvador Investments No 1 y Cia S enC de C V (El Salvador)
Duke Energy International El Salvador, S en C de CV (El Salvador)
Duke Energy International Electroquil Holdings, LLC (Delaware)
Duke Energy International Espana Holdings, S L (Spain)
Duke Energy International Finance (UK) Limited (United Kingdom)
Duke Energy International Guatemala Holdings No 1, Ltd (Bermuda)
Duke Energy International Guatemala Holdings No 2, Ltd (Bermuda)
Duke Energy International Guatemala Holdings No 3 (Cayman Islands)

Duke Energy International Guatemala Limitada (Guatemala)
Duke Energy International Guatemala y Compania Sociedad en Comandita por Acciones (Guatemala)
Duke Energy International Investments No 2 Ltd (Bermuda)
Duke Energy International Latin America, Ltd (Bermuda)
Duke Energy International Mexico, S A de C V (Mexico)
Duke Energy International Netherlands Financial Services B V (Netherlands)
Duke Energy International Operaciones Guatemala Limitada (Guatemala)
Duke Energy International Peru Inversiones No 1, S R L (Peru)
Duke Energy International Peru Investments No 1, Ltd (Bermuda)
Duke Energy International PJP Holdings (Mauritius) Ltd (Republic of Mauritius)
Duke Energy International PJP Holdings, Ltd (Bermuda)
Duke Energy International Pty Ltd (Australia)
Duke Energy International Services (UK) Limited (United Kingdom)
Duke Energy International Southern Cone SRL (Argentina)
Duke Energy International Trading and Marketing (UK) Limited (United Kingdom)
Duke Energy International Transmision Guatemala Limitada (Guatemala)
Duke Energy International Uruguay Holdings, LLC (Delaware)
Duke Energy International Uruguay Investments, S R L (Uruguay)
Duke Energy International, Brasil Ltda (Brazil)
Duke Energy International, Geracao Paranapanema S A (Brazil)
Duke Energy International, LLC (Delaware)
Duke Energy Kentucky, Inc (Kentucky)
Duke Energy Lantana, LLC (Delaware)
Duke Energy Marketing America, LLC (Delaware)
Duke Energy Marketing Canada Corp (Delaware)
Duke Energy Marketing Corp (Nevada)
Duke Energy Marketing Limited Partnership (Alberta, Canada)
Duke Energy Merchant Finance, LLC (Delaware)
Duke Energy Merchants Investments (UK) Limited (England and Wales)
Duke Energy Merchants Trading and Marketing (UK) Limited (England)
Duke Energy Merchants UK LLP (England and Wales)
Duke Energy Merchants, LLC (Delaware)
Duke Energy Moapa, LLC (Delaware)
Duke Energy Murray Operating, LLC (Delaware)
Duke Energy North America, LLC (Delaware)
Duke Energy Ohio, Inc (Ohio)
Duke Energy One, Inc (Delaware)
Duke Energy Peru Holdings S R L (Peru)
Duke Energy Power Assets Holding, Inc (Colorado)
Duke Energy Providence, LLC (Delaware)
Duke Energy Receivables Finance Company, LLC (Delaware)
Duke Energy Registration Services, Inc (Delaware)

Duke Energy Retail Sales, LLC (Delaware)
Duke Energy Royal, LLC (Delaware)
Duke Energy Services Canada Ltd (Alberta—Canada)
Duke Energy Services Ireland Limited (Republic of Ireland)
Duke Energy Services, Inc (Delaware)
Duke Energy Shared Services, Inc (Delaware)
Duke Energy St Francis, LLC (Delaware)
Duke Energy Supply Chain Services, LLC (Delaware)
Duke Energy Trading and Marketing, LLC (Delaware)
Duke Energy Trading Exchange, LLC (Delaware)
Duke Engineering & Services (Europe) Inc (Delaware)
Duke Engineering & Services International, Inc (Cayman Islands)
Duke Investments, LLC (Delaware)
Duke Java, Inc (Nevada)
Duke Project Services Australia Pty Ltd (Australia)
Duke Project Services, Inc (North Carolina)
Duke Supply Network, LLC (Delaware)
Duke Technologies, Inc (Delaware)
Duke Trading Do Brasil Ltda (Brazil)
Duke Ventures II, LLC (Delaware)
Duke Ventures, LLC (Nevada)
Duke/Fluor Daniel (North Carolina)
Duke/Fluor Daniel Caribbean, S E (Puerto Rico)
Duke/Fluor Daniel El Salvador S A de C V (El Salvador)
Duke/Fluor Daniel International (Nevada)
Duke/Fluor Daniel International Services (Nevada)
Duke/Fluor Daniel International Services (Trinidad) Ltd (Trinidad and Tobago)
Duke/Louis Dreyfus LLC (Nevada)
Duke-Cadence, Inc (Indiana)
DukeNet Communication Services, LLC (Delaware)
DukeNet Communications, LLC (Delaware)
Duke-Reliant Resources, Inc (Delaware)
DukeTec I, LLC (Delaware)
DukeTec II, LLC (Delaware)
DukeTec, LLC (Delaware)
Eastman Whipstock do Brasil Ltda (Brazil)
Eastman Whipstock, S A (Argentina)
Eastover Land Company (Kentucky)
Eastover Mining Company (Kentucky)
Electroguayas, Inc (Cayman Islands)
Electroquil, S A (Guayaquil, Ecuador)
Empresa Electrica Corani, S A (Bolivia)

Energy Pipelines International Company (Delaware)
EnerVest Olanta, LLC (Texas)
Environmental Wood Supply, LLC (Minnesota)
Eteselva S R L (Peru)
eVent Resources Holdings LLC (Delaware)
eVent Resources I LLC (Delaware)
Fiber Link, LLC (Indiana)
Fort Drum Cogenco, Inc (New York)
Gas Integral S R L (Peru)
Generadora La Laguna Duke Energy International Guatemala y Cia , S C A (Guatemala)
GNE Holdings, LLC (Delaware)
Green Power G P , LLC (Delaware)
Green Power Holdings, LLC (Delaware)
Green Power Limited, LLC (Delaware)
Greenville Gas and Electric Light and Power Company (South Carolina)
Hidroelectrica Cerros Colorados, S A (Argentina)
IGC Aguaytia Partners, LLC (Cayman Islands)
II Tryon Investment Trading Society (North Carolina)
Inversiones Duke Bolivia S A (Bolivia)
KO Transmission Company (Kentucky)
Lansing Grand River Utilities, LLC (Delaware)
LH1, LLC (Delaware)
Lizacorp S A (Ecuador)
MCP, LLC (South Carolina)
Miami Power Corporation (Indiana)
Midlands Hydrocarbons (Bangladesh) Limited (England)
Morris Gasco, LLC (Delaware)
MP Supply, Inc (North Carolina)
National Methanol Company (IBN SINA) (Saudi Arabia)
NorthSouth Insurance Company Limited (Bermuda)
Oak Mountain Products, LLC (Delaware)
Ohio River Valley Propane, LLC (Delaware)
P.I.D C Aguaytia, LLC (Delaware)
Pan Service Company (Delaware)
PanEnergy Corp (Delaware)
Peru Energy Holdings, LLC (Delaware)
Power Construction Services Pty Ltd (Western Australia)
Reliant Services, LLC (Indiana)
Seahorse do Brasil Servicos Maritimos Ltda (Brazil)
South Construction Company, Inc (Indiana)
South Houston Green Power, L P (Delaware)
Southeastern Energy Services, Inc (Delaware)
Southern Power Company (North Carolina)
Spruce Mountain Investments, LLC (Delaware)
Spruce Mountain Products, LLC (Delaware)
St. Paul Cogeneration, LLC (Minnesota)
SUEZ/VWNA/DEGS of Lansing, LLC (Delaware)
SUEZ-DEGS of Lansing, LLC (Delaware)
SUEZ-DEGS of Orlando, LLC (Delaware)
SUEZ-DEGS, LLC (Delaware)
SYNCAP II, LLC (Delaware)
TEC Aguaytia, Ltd (Bermuda)
Termoselva S R L (Peru)
Texas Eastern (Bermuda) Ltd (Bermuda)
Texas Eastern Arabian Ltd (Bermuda)
Tri-State Improvement Company (Ohio)
UK Electric Power Limited (England)
Wateree Power Company (South Carolina)
Western Carolina Power Company (North Carolina)

EXHIBIT 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statements No. 333-132996 and 333-132992 on Form S-3 and Registration Statements No 333-134080 and 333-132933 on Form S-8 of Duke Energy Corporation of our reports dated March 1, 2007, relating to the financial statements and financial statement schedule of Duke Energy Corporation (which report expresses an unqualified opinion and includes explanatory paragraphs regarding the adoption of a new accounting standard and the January 2, 2007 spin-off of the Company's natural gas businesses) and management's report on the effectiveness of internal control over financial reporting, appearing in this Annual Report on Form 10-K of Duke Energy Corporation for the year ended December 31, 2006

/s/ DELOITTE & TOUCHE LLP
Charlotte, North Carolina
March 1, 2007

EXHIBIT 23.2

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Partners of TEPPCO Partners, L.P.:

We consent to the incorporation by reference in the registration statements Nos. 333-132996 and 333-132992 on Form S-3 and Nos. 333-134080 and 333-132933 on Form S-8 of Duke Energy Corporation of our report dated February 28, 2006, except for the effects of discontinued operations, as discussed in Note 5, which is as of June 1, 2006, with respect to the consolidated balance sheets of TEPPCO Partners, L.P. and subsidiaries as of December 31, 2005 and 2004, and the related consolidated statements of income, partners' capital and comprehensive income, and cash flows for each of the years in the three-year period ended December 31, 2005, which report appears herein.

Our report dated February 28, 2006, except for the effects of discontinued operations, as discussed in Note 5, which is as of June 1, 2006, with respect to the consolidated balance sheets of TEPPCO Partners, L.P. and subsidiaries as of December 31, 2005 and 2004 and the related consolidated statements of income, partners' capital and comprehensive income, and cash flows for each of the years in the three-year period ended December 31, 2005, contains a separate paragraph that states that as discussed in Note 20 to the consolidated financial statements, the Partnership has restated its consolidated balance sheet as of December 31, 2004, and the related consolidated statements of income, partners' capital and comprehensive income, and cash flows for the years ended December 31, 2004 and 2003.

/s/ KPMG LLP
Houston, Texas
March 1, 2007

Exhibit 24.1

DUKE ENERGY CORPORATION

Power of Attorney

FORM 10-K

Annual Report Pursuant to Section 13 or 15(d)
of the Securities Exchange Act of 1934
For the fiscal year ended December 31, 2006
(Annual Report)

The undersigned **Duke Energy Corporation**, a Delaware corporation and certain of its officers and/or directors, do each hereby constitute and appoint David L Hauser, David S Maltz and Steven K Young, and each of them, to act as attorneys-in-fact for and in the respective names, places and stead of the undersigned, to execute, seal, sign and file with the Securities and Exchange Commission the Annual Report of said Duke Energy Corporation on Form 10-K and any and all amendments thereto, hereby granting to said attorneys-in-fact, and each of them, full power and authority to do and perform all and every act and thing whatsoever requisite, necessary or proper to be done in and about the premises, as fully to all intents and purposes as the undersigned, or any of them, might or could do if personally present, hereby ratifying and approving the acts of said attorneys-in-fact

Executed as of the 27th day of February, 2007.

DUKE ENERGY CORPORATION

By: /s/ JAMES E ROGERS

Chairman, President and
Chief Executive Officer

(Corporate Seal)

ATTEST:

/S/ SUE C. HARRINGTON

Assistant Secretary

/S/ JAMES E. ROGERS James E Rogers	Chairman, President and Chief Executive Officer (Principal Executive Officer and Director)
/S/ DAVID L HAUSER David L Hauser	Group Executive and Chief Financial Officer (Principal Financial Officer)
/S/ STEVEN K YOUNG Steven K Young	Senior Vice President and Controller (Principal Accounting Officer)
/S/ WILLIAM BARNET, III William Barnet, III	(Director)
/S/ G. ALEX BERNHARDT G. Alex Bernhardt	(Director)
/S/ MICHAEL G BROWNING Michael G Browning	(Director)
/S/ PHILLIP R. COX Phillip R Cox	(Director)
/S/ ANN M. GRAY Ann M Gray	(Director)

/S/ JAMES H. HANCE, JR.	(Director)
James H Hance, Jr	
/S/ JAMES T. RHODES	(Director)
James T Rhodes	
/S/ MARY L. SCHAPIRO	(Director)
Mary L. Schapiro	
/S/ DUDLEY S. TAFT	(Director)
Dudley S Taft	

Exhibit 24.2

DUKE ENERGY CORPORATION

CERTIFIED RESOLUTIONS

Form 10-K Annual Report Resolutions

FURTHER RESOLVED, That each officer and director who may be required to execute such 2006 Form 10-K or any amendments thereto (whether on behalf of the Corporation or as an officer or director thereof or by attesting the seal of the Corporation or otherwise) be and hereby is authorized to execute a Power of Attorney appointing David L. Hauser, David S. Maltz and Steven K. Young, and each of them, as true and lawful attorneys and agents to execute in his or her name, place and stead (in any such capacity) such 2006 Form 10-K, as may be deemed necessary and proper by such officers, and any and all amendments thereto and all instruments necessary or advisable in connection therewith, to attest the seal of the Corporation thereon and to file the same with the Securities and Exchange Commission, each of said attorneys and agents to have power to act with or without the others and to have full power and authority to do and perform in the name and on behalf of each of such officers and directors, or both, as the case may be, every act whatsoever necessary or advisable to be done in the premises as fully and to all intents and purposes as any such officer or director might or could do in person.

* * * * * * *

I, JULIA S. JANSON, Senior Vice President, Ethics and Compliance and Corporate Secretary of Duke Energy Corporation, do hereby certify that the foregoing is a full, true and complete extract from the Minutes of the regular meeting of the Board of Directors of said Corporation held on February 27, 2007, at which meeting a quorum was present.

IN WITNESS WHEREOF, I have hereunto set my hand and affixed the Corporate Seal of said Duke Energy Corporation, this the 27th day of February, 2007

/s/ JULIA S JANSON

Julia S Janson, Senior Vice President, Ethics and Compliance and Corporate Secretary

EXHIBIT 31.1

CERTIFICATION OF THE CHIEF EXECUTIVE OFFICER PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, James E Rogers, certify that:

1) I have reviewed this annual report on Form 10-K of Duke Energy Corporation;
2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3) Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4) The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Acts Rules 13a – 15(f) and 15d – 15(f)) for the registrant and have:
   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5) The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting

Date: March 1, 2007

/s/ JAMES E ROGERS

James E Rogers
Chairman, President and
Chief Executive Officer

EXHIBIT 31.2

CERTIFICATION OF THE CHIEF FINANCIAL OFFICER PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, David L Hauser, certify that:

1) I have reviewed this annual report on Form 10-K of Duke Energy Corporation;

2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3) Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4) The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Acts Rules 13a – 15(f) and 15d – 15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5) The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 1, 2007

/s/ DAVID L. HAUSER

David L. Hauser
Group Executive and
Chief Financial Officer

EXHIBIT 32.1

CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350, AS ADOPTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Duke Energy Corporation ("Duke Energy") on Form 10-K for the period ending December 31, 2006 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, James E Rogers, Chairman, President and Chief Executive Officer of Duke Energy, certify, pursuant to 18 U S C section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Duke Energy

/s/ JAMES E ROGERS

James E Rogers
Chairman, President and Chief Executive Officer
March 1, 2007

EXHIBIT 32.2

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Duke Energy Corporation ("Duke Energy") on Form 10-K for the period ending December 31, 2006 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, David L. Hauser, Group Executive and Chief Financial Officer of Duke Energy, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Duke Energy

/s/ DAVID L. HAUSER

David L. Hauser
Group Executive and Chief Financial Officer
March 1, 2007