Spectra Energy Corp.
Form 10-K
February 29, 2008
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UNITED STATES SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-K

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

For the fiscal year ended December 31, 2007 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 1-33007

SPECTRA ENERGY CORP

(Exact name of registrant as specified in its charter)

Delaware	20-5413139
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
5400 Westheimer Court, Houston, Texas	77056
(Address of principal executive offices)	(Zip Code)

713-627-5400

(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, par value $0.001	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None.

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes x 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 x

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 x 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, a non-accelerated filer, or a smaller reporting company. See the definitions of large accelerated filer, accelerated filer, and smaller reporting company in Rule 12b-2 of the Exchange Act.

Large accelerated filer x Accelerated filer ¨ Non-accelerated filer ¨ Smaller reporting company ¨

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ¨ No x

Estimated aggregate market value of the common equity held by nonaffiliates of the registrant at June 30, 2007: $16,400,000,000.

Number of shares of Common Stock, $0.001 par value, outstanding at February 19, 2008: 632,536,965

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the proxy statement for the 2008 Annual Meeting of Shareholders are incorporated by reference in Part III.

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SPECTRA ENERGY CORP

FORM 10-K FOR THE YEAR ENDED

DECEMBER 31, 2007

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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, 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 that affect cost and investment recovery, have an effect on rate structure, and affect the speed at and degree to which competition enters the natural gas industries;
- outcomes of litigation and regulatory investigations, proceedings or inquiries;
- weather and other natural phenomena, including the economic, operational and other effects of hurricanes and storms;
- the timing and extent of changes in commodity prices, interest rates and foreign currency exchange rates;
- general economic conditions, including any potential effects arising from terrorist attacks and any consequential or other hostilities;
- changes in environmental, safety and other laws and regulations;
- results of financing efforts, including the ability to obtain financing on favorable terms, which can be affected by various factors, including credit ratings and general economic conditions;
- increases in the cost of goods and services required to complete capital projects;
- declines in the market prices of equity securities and resulting funding requirements for defined benefit pension plans;
- growth in opportunities, including the timing and success of efforts to develop domestic and international pipeline, storage, gathering, processing and other infrastructure projects and the effects of competition;
- the performance of natural gas transmission and storage, distribution, and gathering and processing facilities;
- the extent of success in connecting natural gas supplies to gathering, processing and transmission systems and in connecting to expanding gas markets;

the effects of accounting pronouncements issued periodically by accounting standard-setting bodies;

conditions of the capital markets during the periods covered by the forward-looking statements; and

the ability to successfully complete merger, acquisition or divestiture plans; regulatory or other limitations imposed as a result of a merger, acquisition or divestiture; and the success of the business following a merger, acquisition or divestiture.

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 Spectra Energy Corp has described. Spectra Energy Corp undertakes no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

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PART I

Item 1. Business.

General

Spectra Energy Corp, through its subsidiaries and equity affiliates (collectively, Spectra Energy), owns and operates a large and diversified portfolio of complementary natural gas-related energy assets and is one of North America s leading natural gas infrastructure companies. For close to a century, Spectra Energy and its predecessor companies have developed critically important pipelines and related energy infrastructure connecting natural gas supply sources to premium markets. Spectra Energy operates in three key areas of the natural gas industry: transmission and storage, distribution, and gathering and processing. Based in Houston, Texas, Spectra Energy provides transportation and storage of natural gas to customers in various regions of the Eastern and Southeastern United States, the Maritime Provinces in Canada and the Pacific Northwest in the United States and Canada, and in the province of Ontario in Canada. It 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. Spectra Energy also has a 50% ownership in DCP Midstream, LLC, (DCP Midstream), one of the largest natural gas gatherers and processors in the United States, based in Denver, Colorado. Spectra Energy s operations are subject to various federal, state, provincial and local laws and regulations.

Spectra Energy s natural gas pipeline systems consist of approximately 18,000 miles of transmission pipelines. Spectra Energy s proportional throughput for its pipelines totaled 3,642 trillion British thermal units (TBtu) in 2007 compared to 3,260 TBtu in 2006. These amounts include throughput on wholly owned U.S. and Canadian pipelines and Spectra Energy s proportional share of throughput on pipelines that are not wholly owned. Spectra Energy s storage facilities provide approximately 272 billion cubic feet (Bcf) of storage capacity in the United States and Canada.

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Spin-off from Duke Energy Corporation

On January 2, 2007, Duke Energy Corporation (Duke Energy) completed the spin-off of Spectra Energy. Duke Energy contributed the natural gas businesses, primarily comprised of the Natural Gas Transmission and Field Services business segments of Duke Energy that were owned through Duke Energy s then wholly owned subsidiary, Spectra Energy Capital, LLC (Spectra Capital). Duke Energy contributed its ownership interests in Spectra Capital to Spectra Energy and all of the outstanding common stock of Spectra Energy was distributed to Duke Energy s shareholders.

Businesses of Spectra Energy

Subsequent to the reorganization and spin-off of Spectra Energy from Duke Energy, Spectra Energy manages its business in four reportable segments: U.S. Transmission, Distribution, Western Canada Transmission & Processing, and Field Services. The remainder of Spectra Energy s business operations is presented as Other and consists of unallocated corporate costs, wholly owned captive insurance subsidiaries, employee benefit plan assets and liabilities and other miscellaneous activities. The following sections describe the operations of each of Spectra Energy s businesses. For financial information on Spectra Energy s business segments, see Part II, Item 8. Financial Statements and Supplementary Data, Note 4 of Notes to Consolidated Financial Statements.

U.S. TRANSMISSION

Spectra Energy s U.S. Transmission business provides transportation and storage of natural gas for customers in various regions of the Eastern and Southeastern United States and the Maritime Provinces in Canada. Spectra Energy s U.S. pipeline systems consist of more than 13,500 miles of transmission pipelines with five primary transmission systems: Texas Eastern Transmission, L.P. (Texas Eastern), Algonquin Gas Transmission, LLC (Algonquin), East Tennessee Natural Gas, LLC (East Tennessee), Maritimes & Northeast Pipeline, LLC and Maritimes & Northeast Pipeline, L.P. (collectively, Maritimes & Northeast Pipeline), and Gulfstream Natural Gas System, LLC (Gulfstream). These pipeline systems receive natural gas from major North American producing regions for delivery to markets. U.S. Transmission s proportional throughput for its pipelines totaled 2,202 TBtu in 2007 compared to 1,930 TBtu in 2006. This includes throughput on wholly owned pipelines and its proportional share of throughput on pipelines that are not wholly owned. A majority of contracted transportation volumes are under long-term firm service agreements. Interruptible transportation services are provided on a short-term or seasonal basis. In the course of providing transportation services, U.S. Transmission also processes natural gas on its Texas Eastern system. Demand on the pipeline systems is seasonal, with the highest throughput occurring during colder periods in the first and fourth calendar quarters.

Most of U.S. Transmission s pipeline and storage operations are regulated by the Federal Energy Regulatory Commission (FERC) and are subject to the jurisdiction of various federal state and local environmental agencies.

In July 2007, Spectra Energy completed its initial public offering (IPO) of Spectra Energy Partners, LP (Spectra Partners), a newly formed, midstream energy master limited partnership which is part of the U.S. Transmission segment. Spectra Energy retained an 83% equity interest in Spectra Partners, which currently owns 100% of East Tennessee, 50% of Market Hub Partners, LLC (MHP) and a 24.5% interest in Gulfstream. Spectra Energy retained a 50% direct ownership interest in MHP and a 25.5% direct ownership interest in Gulfstream. Spectra Partners is a separate, publicly traded entity which trades on the New York Stock Exchange under the symbol SEP.

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Texas Eastern

The Texas Eastern 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 8,700 miles of pipeline and 73 compressor stations (facilities that increase the pressure of gas to facilitate its pipeline transmission). 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 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 73 Bcf.

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Algonquin

The Algonquin pipeline 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.

East Tennessee

East Tennessee 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 21 compressor stations. East Tennessee has a liquefied natural gas (LNG) storage facility in Tennessee with a total working capacity of 1.1 Bcf. East Tennessee also connects to storage facilities in Virginia owned by Spectra Energy that have a working gas capacity of approximately 5 Bcf.

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Spectra Energy has an effective 83% ownership interest in East Tennessee through its ownership of Spectra Partners.

Maritimes & Northeast Pipeline

Maritimes & Northeast Pipeline s gas transmission system is operated primarily through Maritimes & Northeast Pipeline, LP and Maritimes & Northeast Pipeline, LLC, which are owned 78% by Spectra Energy. The Maritimes & Northeast Pipeline transmission system extends approximately 900 miles from producing fields in Nova Scotia through New Brunswick, Maine, New Hampshire and Massachusetts, connecting to Algonquin in Beverly, Massachusetts. There are two compressor stations on the system.

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Gulfstream

Spectra Energy also has an effective 46% investment in Gulfstream, a 700-mile interstate natural gas pipeline system operated jointly by Spectra Energy and The Williams Companies, Inc. Gulfstream transports natural gas from Mississippi and Alabama, crossing the Gulf of Mexico to markets in central and southern Florida. Gulfstream has one compressor station. Gulfstream is owned 25.5% by Spectra Energy, 24.5% by Spectra Partners and 50% by The Williams Companies, Inc.

Market Hub Partners, LLC

Spectra Energy has an effective 92% ownership interest in Market Hub Partners, LLC (MHP), which owns and operates two natural gas storage facilities, Moss Bluff and Egan, with a total storage capacity of approximately 35 Bcf. The Moss Bluff facility consists of three storage caverns located in Southeast Texas and has access to five pipeline systems including the Texas Eastern system. The Egan facility consists of three storage caverns located in South Central Louisiana and has access to eight pipeline systems including the Texas Eastern system. MHP is a general partnership in which Spectra Energy and Spectra Partners each have a 50% interest.

Saltville Gas Storage L.L.C.

Saltville Gas Storage Company L.L.C. (Saltville) owns and operates natural gas storage facilities with a total storage capacity of approximately 5 Bcf. The storage facilities interconnect with Virginia Gas Pipeline Company and East Tennessee. This salt cavern facility offers high deliverability capabilities and is strategically located near markets in Tennessee, Virginia and North Carolina. Saltville is currently capable of delivering up to 275 million cubic feet of natural gas per day to the surrounding region.

In December 2007, Spectra Energy announced an agreement to sell Saltville and the P-25 Pipeline (a 72-mile, eight-inch natural gas pipeline) to Spectra Partners for $107 million, consisting of newly issued partnership units and approximately $5 million in cash. The transaction is expected to close during the second quarter of 2008, pending required regulatory approvals.

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Competition

Spectra Energy s U.S. Transmission transportation and storage businesses compete with similar facilities that serve its supply and market areas in the transportation and storage of natural gas. The principal elements of competition are rates, terms of service, and flexibility and reliability of service.

The natural gas that Spectra Energy transports in its transmission business competes with other forms of energy available to its customers and end-users, including electricity, coal, propane and fuel oils. Factors that influence the demand for natural gas include 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.

Customers and Contracts

In general, Spectra Energy s U.S. Transmission pipelines provide transportation and storage services to local distribution companies (LDCs), electric power generators, exploration and production companies, and industrial and commercial customers, as well as energy marketers. Transportation and storage services are provided under firm agreements where customers reserve capacity in pipelines and storage facilities. The vast majority of these agreements provide for fixed reservation charges that are paid monthly regardless of actual volumes transported on the pipelines or injected or withdrawn from Spectra Energy s storage facilities plus a small variable component that is based on volumes transported to recover variable costs.

Spectra Energy also provides interruptible transportation and storage services where customers can use capacity if it is available at the time of the request. Payments under these services are based on volumes transported or stored. These operations also provide a variety of other value-added services including natural gas parking, loaning and balancing services to meet customers needs.

DISTRIBUTION

Spectra Energy provides distribution services in Canada through its subsidiary, Union Gas Limited (Union Gas). Union Gas owns pipeline, storage and compression facilities used in the transportation, storage and distribution of natural gas. Union Gas system consists of approximately 37,000 miles of distribution main and service 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 2,800 miles of high-pressure pipeline and six mainline compressor stations.

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. Union Gas is regulated by the Ontario Energy Board (OEB) pursuant to the provisions of the Ontario Energy Board Act (1998) and is subject to regulation in a number of areas including rates.

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Union Gas storage and transmission system forms an important link in moving natural gas from Western Canadian and U.S. supply basins to Central Canadian and Northeastern U.S. markets.

Competition

As Union Gas distribution business is regulated by the OEB, it is not generally subject to third-party competition within its distribution franchise area, although as a result of a 2006 decision by the OEB, physical bypass of Union Gas facilities even within its distribution franchise area may be permitted. In addition, other companies could enter Union Gas markets or regulations could change.

Union Gas competes with other forms of energy available to its customers and end-users, including electricity, coal, propane and fuel oils. Factors that influence the demand for natural gas include 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.

In November 2006, the OEB issued a decision on the regulation of rates for gas storage services in Ontario. As a result of its finding that the market for storage services is competitive, the OEB will not regulate the rates for storage services to customers outside Union Gas franchise area or the rates for new storage services to customers within its franchise area. For these unregulated services, Union Gas will compete against third-party storage providers for storage on the basis of price, terms of service, and flexibility and reliability of service. Existing storage services to customers within Union Gas franchise area will continue to be provided at cost-based rates and will not be subject to third-party competition.

Customers and Contracts

The rates that Union Gas charges for its regulated services are subject to the approval of the OEB. Union Gas distribution service area extends throughout Northern Ontario from the Manitoba border to the North Bay/Muskoka area, through Southern Ontario from Windsor to just west of Toronto, and across Eastern Ontario from Port Hope to Cornwall. Union Gas franchise area has a population of approximately four million people and a diversified commercial and industrial base.

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Union Gas distribution services to power generation and industrial customers are affected by weather, economic conditions and the price of competitive energy sources. Most of Union Gas power generation, industrial and large commercial customers, and a portion of residential customers, purchase their natural gas directly from suppliers or marketers. Because Union Gas earns income from the distribution of natural gas and not the sale of the natural gas commodity, gas distribution margins are not affected by the source of customers gas supply.

Union Gas also provides natural gas storage and transportation services for other utilities and energy market participants in Ontario, Quebec and the United States. Transportation and storage customers include large Canadian natural gas transmission and distribution companies. A substantial amount of Union Gas annual transportation and storage revenue is generated by fixed demand charges. The average term of these contracts is approximately five years, with the longest contract term being almost 20 years.

WESTERN CANADA TRANSMISSION & PROCESSING

Spectra Energy s Western Canada Transmission & Processing business is comprised of the BC Pipeline and Field Services operations, the Midstream operations and the natural gas liquids (NGL) Marketing operations.

BC Pipeline and Field Services provide natural gas transportation and gas gathering and processing services. BC Pipeline is regulated by the National Energy Board (NEB) under full cost of service regulation, and transports processed natural gas from facilities primarily in northeast British Columbia (BC) to markets in the lower mainland of BC and the U.S. Pacific Northwest. The BC Pipeline has approximately 1,800 miles of transmission pipeline in British Columbia and Alberta, as well as 18 mainline compressor stations. Throughput for the BC Pipeline totaled 596 TBtu in 2007 compared to 594 TBtu in 2006.

The BC Field Services business, which is regulated by the NEB under a light-handed regulatory model, consists of raw gas gathering pipelines and gas processing facilities, primarily in northeast BC. These facilities provide services to natural gas producers to remove impurities from the raw gas stream including water, carbon dioxide, hydrogen sulfide and other substances. Where required, these facilities also remove various NGLs for subsequent sale. The BC Field Services business includes five gas processing plants located in British Columbia, 22 field compressor stations and approximately 1,600 miles of gathering pipelines.

The Midstream business provides similar gas gathering and processing services in BC and Alberta through Spectra Energy s 46% interest in Spectra Energy Income Fund (the Income Fund), a Canadian income trust. The Midstream business consists of 13 natural gas processing plants and approximately 1,000 miles of gathering pipelines.

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The Empress NGL Marketing business provides NGL extraction, fractionation, transportation, storage and marketing services to western Canadian producers and NGL customers throughout Canada and the northern tier of the U.S. Assets include, among other things, a majority ownership interest in an NGL extraction plant, an integrated NGL fractionation facility, an NGL transmission pipeline, seven terminals where propane, butane and condensate are loaded for shipping or transferred into product sales pipelines, two NGL storage facilities, and an NGL marketing and gas supply business. The Empress fractionation plant is located in Empress, Alberta.

Competition

Western Canada Transmission & Processing businesses compete with third-party midstream companies, exploration and production companies and pipelines in the transportation of natural gas and the extraction and marketing of NGL products. The Company competes directly with other pipeline facilities serving its market areas. The principal elements of competition are rates, terms of service, and flexibility and reliability of service. Customer demands for toll certainty and lower cost tailored services have promoted increased competition from other midstream service companies and producers.

Natural gas competes with other forms of energy available to Western Canada Transmission & Processing s customers and end-users, including electricity, coal and fuel oils. The primary competitive factor is price. Changes in the availability or price 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 affect the demand for natural gas in the areas served by Spectra Energy.

In addition to the fee for service pipeline and gathering and processing businesses, Spectra Energy competes with other NGL extraction facilities at Empress, Alberta for the right to extract and purchase NGLs from natural gas shippers on the TransCanada pipeline system. To extract and acquire NGLs, Spectra Energy must be competitive in the premium or fee it pays to natural gas shippers.

Customers & Contracts

Spectra Energy s BC Pipeline provides: (i) transportation services from the outlet of natural gas processing plants in Northeast BC to LDCs, end-use industrial and commercial customers, and exploration and production companies requiring transportation services to the nearest natural gas trading hub; and (ii) transportation services

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primarily to downstream markets in the Pacific Northwest (both United States and Canada.) Major customer segments include LDCs, electric power generators, exploration and production companies, gas marketers, and industrial and commercial end users.

The majority of transportation services are provided under firm agreements, which provide for fixed reservation charges that are paid monthly regardless of actual volumes transported on the pipeline, plus a small variable component that is based on volumes transported to recover variable costs. Spectra Energy s BC Pipeline also provides interruptible transportation services where customers can use capacity if it is available at the time of request and payments under these services are based on volumes transported.

The largest portion of Spectra Energy s business in Western Canada is represented by the BC Field Services and Midstream operations providing raw natural gas gathering and processing services to exploration and production companies under firm agreements which are primarily fee-for-service contracts. These operations provide both firm and interruptible services.

The NGL extraction operation at Empress, Alberta has capacity to produce approximately 50,000 barrels of NGLs per day comprised of approximately 50% ethane, 32% propane, 12% butanes and 6% condensate. After NGLs are extracted, Spectra Energy fractionates the NGLs into ethane, propane, butane, and condensate and sells these products into the marketplace. All ethane is sold to Alberta-based petrochemical companies. The majority of propane is sold to propane wholesalers. Butane is sold mainly into the motor gasoline refinery market and condensate sales are directed to the crude blending and crude diluent markets. The prices Spectra Energy can obtain for these products is affected by numerous factors including competition, weather, transportation costs and supply and demand factors.

FIELD SERVICES

Field Services consists of Spectra Energy s 50% investment in DCP Midstream, which is accounted for as an equity investment. DCP Midstream gathers and processes natural gas, and fractionates, markets and trades NGLs. ConocoPhillips owns the remaining 50% interest in DCP Midstream.

DCP Midstream operates in 25 states in the United States. DCP Midstream s gathering systems include connections to several interstate and intrastate natural gas and NGL pipeline systems and one natural gas storage facility. DCP Midstream gathers raw natural gas through gathering systems located in eight major natural gas producing regions: Permian Basin, Mid-Continent, Rocky Mountain, East Texas-North Louisiana, Barnett Shale, Gulf Coast, South Texas and Central Texas. DCP Midstream owns or operates approximately 58,000 miles of gathering and transmission pipe, with approximately 37,000 active receipt points.

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DCP Midstream s 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. DCP Midstream 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. DCP Midstream 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, DCP Midstream operates a propane wholesale marketing business. DCP Midstream 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. DCP Midstream markets residue gas directly or through its wholly owned gas marketing company and its affiliates. DCP Midstream also stores residue gas at its 8 Bcf natural gas storage facility located in Southeast Texas.

DCP Midstream 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. DCP Midstream 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.

DCP Midstream s operating results are significantly affected by changes in average NGL and crude oil prices, which increased approximately 18% and 10%, respectively, in 2007 compared to 2006. DCP Midstream closely monitors the risks associated with these price changes. See Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Quantitative and Qualitative Disclosures About Market Risk for a discussion of DCP Midstream s exposure to changes in commodity prices.

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Competition

In gathering and processing natural gas and in marketing and transporting natural gas and NGLs, DCP Midstream 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.

Customers and Contracts

DCP Midstream 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 DCP Midstream s NGL sales are made at market-based prices, including approximately 40% of its NGL production that is committed to ConocoPhillips and its affiliate, Chevron Phillips Chemical Company LLC, under existing contracts that have primary terms that are effective until January 1, 2015. In 2007, ConocoPhillips and Chevron Phillips Chemical Company LLC, combined, represented approximately 21% of DCP Midstream s consolidated revenues.

The residual natural gas (primarily methane) that results from processing raw natural gas is sold at market-based prices to marketers and end-users. End-users include large industrial companies, natural gas distribution companies and electric utilities.

DCP Midstream purchases or takes custody of substantially all of its raw natural gas from producers, principally under the following types of contractual arrangements:

Percentage-of-proceeds arrangements. In general, DCP Midstream purchases natural gas from producers, transports and processes it and then sells the residue natural gas and NGLs in the market. The payment to the producer is an agreed upon percentage of the proceeds from those sales. DCP Midstream s revenues from these arrangements correlate directly with the price of natural gas and NGLs.

Fee-based arrangements. DCP Midstream receives a fee or fees for the various services it provides including gathering, compressing, treating, processing or transporting natural gas. The revenue DCP Midstream earns from these arrangements is directly related to the volume of natural gas that flows through its systems and is not directly dependent on commodity prices.

Keep-whole and wellhead purchase arrangement. DCP Midstream gathers or purchases raw natural gas from producers for processing and then markets the NGLs. DCP Midstream keeps the producer whole by returning an equivalent amount of natural gas after the processing is complete. DCP Midstream is exposed to the frac-spread, which is the price difference between NGLs and natural gas prices, representing the theoretical gross margin for processing liquids from natural gas.

As defined by the terms of the above arrangements, DCP Midstream also sells condensate, which is generally similar to crude oil and is produced in association with natural gas gathering and processing.

Supplies and Raw Materials

Spectra Energy purchases a variety of manufactured equipment and materials for use in operations and expansion projects. The primary equipment and materials utilized in operations and project execution processes are steel pipe, compression engines, valves, fittings, polyethylene plastic pipe, gas meters and other consumables.

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Spectra Energy operates a North American supply chain management network with employees dedicated to this function in the United States and Canada. The supply chain management group uses the scale of Spectra Energy to maximize the efficiency of supply networks where applicable. DCP Midstream performs its own supply chain management function.

Global growth in the energy sector, particularly in North America, and rising international demand have led to increased demand levels and increased costs of steel and other materials used in certain of the manufactured equipment required by Spectra Energy s operations. While some of these increases in price and supplier capacity will be offset through the use of strategic supplier contracts, Spectra Energy expects stable to rising prices and constant to extended lead times for many of these products in 2008 through 2010 compared to the previous three year period. The increasing costs and extended lead times are expected to primarily affect Spectra Energy s expansion project program.

There can be no assurance that the ability to obtain sufficient equipment and materials will not be adversely affected by unforeseen developments. In addition, the price of equipment and materials may vary, perhaps substantially, from year to year.

Regulations

Most of Spectra Energy s U.S. gas transmission pipeline and storage operations are regulated by the FERC. The FERC regulates natural gas transportation in U.S. interstate commerce including the establishment of rates for services. The FERC also regulates the construction of U.S. interstate pipelines and storage facilities including extension, enlargement and abandonment of 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 marketing affiliates and require that U.S. interstate pipelines function independently of their marketing affiliates.

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

Spectra Energy s U.S. Transmission and the DCP Midstream operations are subject to the jurisdiction of the Environmental Protection Agency (EPA) and state and local environmental agencies. See Environmental Matters for a discussion of environmental regulation. Spectra Energy s U.S. interstate natural gas pipelines and certain of DCP Midstream s gathering and transmission pipelines are also subject to the regulations of the Department of Transportation (DOT) concerning pipeline safety.

The natural gas transmission and distribution, and approximately two-thirds of the storage operations in Canada are subject to regulation by the NEB or the provincial agencies in Canada, such as the OEB. These agencies have jurisdiction similar to the FERC for regulating rates, the terms and conditions of service, the construction of additional facilities and acquisitions. Spectra Energy s BC Field Services 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 operations 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.

The intrastate natural gas and NGL pipelines owned by DCP Midstream 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 natural gas gathering and processing activities are not subject to FERC regulation.

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Environmental Matters

Spectra Energy is subject to U.S. federal, state and local laws and regulations, as well as Canadian national and provincial regulations, with regard to air and water quality, hazardous and solid waste disposal and other environmental matters. These regulations often impose substantial testing and certification requirements.

Environmental laws and regulations affecting Spectra Energy include, but are not limited to:

The Clean Air Act, or CAA, and the 1990 amendments to the CAA, as well as state laws and regulations affecting air emissions (including State Implementation Plans related to existing and new national ambient air quality standards), which may limit new sources of air emissions. Spectra Energy s natural gas processing, transmission, and storage assets are considered sources of air emissions, and thus are subject to the CAA. Owners and/or operators of air emission sources, such as Spectra Energy, are responsible for obtaining permits for existing and new sources of air emissions, and for annual compliance and reporting.

The Federal Water Pollution Control Act, which requires permits for facilities that discharge wastewaters into the environment. The Oil Pollution Act (OPA), was enacted in 1990 and amends parts of the Clean Water Act and other statutes as they pertain to the prevention of and response to oil spills. OPA imposes certain spill prevention, control and countermeasure requirements. Although Spectra Energy is primarily a natural gas business, OPA affects its business primarily because of the presence of liquid hydrocarbons (condensate) in its offshore pipelines.

The Comprehensive Environmental Response, Compensation and Liability Act, or CERCLA, which imposes liability for remediation costs associated with environmentally contaminated sites. Under CERCLA, any individual or entity that currently owns or in the past owned or operated a disposal site can be held liable and required to share in remediation costs, as well as transporters or generators of hazardous substances sent to a disposal site. Because of the geographical extent of its operations, Spectra Energy has disposed of waste at many different sites.

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. As part of its business, Spectra Energy generates solid waste within the scope of these regulations and therefore must comply with such regulations.

The Toxic Substances Control Act, which requires that polychlorinated biphenyl (PCB) contaminated materials be managed in accordance with a comprehensive regulatory regime. Because of the historic use of lubricating oils containing PCBs, the internal surfaces of some of Spectra Energy s pipeline systems are contaminated with PCBs and liquids and other materials removed from these pipelines must be managed in compliance with such regulations.

The National Environmental Policy Act, which requires federal agencies to consider potential environmental effects in their decisions, including siting approvals. Many of Spectra Energy s projects require federal agency review, and therefore the environmental effect of proposed projects is a factor in determining whether Spectra Energy will be permitted to complete proposed projects.

The Fisheries Act (Canada), which regulates activities near any body of water in Canada.

The Environmental Management Act (British Columbia), the Environmental Protection and Enhancement Act (Alberta), and the Environmental Protection Act (Ontario), are each provincial laws governing various aspects, including permitting and site remediation obligations, of Spectra Energy s facilities and operations in those provinces.

The Canadian Environmental Protection Act, which among other things, will govern the reduction of greenhouse gas emissions from Spectra Energy operations in Canada. Regulations to be promulgated under the Act will set emission-intensity reduction targets and deadlines for fixed emission caps for nitrogen oxides, sulphur oxides, volatile organic compounds and particulate matter.

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The Alberta Climate Change and Emissions Management Act, which, pursuant to regulations which came into effect in 2007, requires certain facilities to meet annual reductions in emission intensity targets starting in 2007. The Act is applicable to Spectra Energy s Empress and Nevis facilities in Alberta.

For more information on environmental matters involving Spectra Energy, including possible liability and capital costs, see Item 8. Financial Statements and Supplementary Data, Notes 5 and 18 of Notes to Consolidated Financial Statements.

Except to the extent discussed in Notes 5 and 18, 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 Spectra Energy s various business units and is not expected to have a material adverse effect on Spectra Energy s competitive position, consolidated results of operations, financial position and cash flows.

Geographic Regions

For a discussion of Spectra Energy s Canadian operations and the risks associated with them, see Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations, Quantitative and Qualitative Disclosures About Market Risk Foreign Currency Risk, and Notes 4 and 20 of Notes to Consolidated Financial Statements.

Employees

Spectra Energy had approximately 5,100 employees as of December 31, 2007, including approximately 3,300 employees outside of the United States, all in Canada. In addition, DCP Midstream, Spectra Energy s joint venture with ConocoPhillips, employed approximately 2,500 employees as of such date. Approximately 1,500 of Spectra Energy s employees, all of whom are located in Canada, are subject to collective bargaining agreements governing their employment with Spectra Energy. Spectra Energy, through its subsidiaries, reached agreements with all bargaining units with agreements subject to renewal in 2007.

Additional Information

Spectra Energy was incorporated on July 28, 2006 as a Delaware corporation. Its principal executive offices are located at 5400 Westheimer Court, Houston, Texas 77056 and its telephone number is 713-627-5400. Spectra 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 Spectra 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 Spectra Energy, including its reports filed with the SEC, is available through Spectra Energy s web site at http://www.spectraenergy.com. Such reports are accessible at no charge through Spectra Energy s web site and are made available as soon as reasonably practicable after such material is filed with or furnished to the SEC. Spectra Energy s website and the information contained on that site, or connected to that site, are not incorporated by reference into this report.

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Glossary

Terms used to describe Spectra Energy s business are defined below.

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.

Derivative. A financial instrument or contract in which the 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.

Distribution System. The system of pipelines, services and equipment which carry or control the supply of natural gas from the point of local supply to customers.

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.

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

Frac-spread. The price difference between NGLs and natural gas prices, representing the theoretical gross margin for processing liquids from natural gas.

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

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

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 gas for ultimate consumption.

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

Organic Growth. Growth due to the expansion or optimization of existing assets.

Residue Gas. Gas remaining after the processing of natural gas.

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Supply Push/Market Pull. Supply push is when producers agree to pay to transport specified volumes of natural gas in order to support the construction of new pipelines. Market pull is taking gas away from established liquid supply points and building pipeline transportation capacity to satisfy end-user demand in new markets or demand growth in existing markets.

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

Transmission System. 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.

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Executive Officers

The following table sets forth information regarding Spectra Energy s executive officers. With the exception of Mr. Capps, each of the individuals set forth below assumed their current position immediately before Spectra Energy s listing on the New York Stock Exchange in January 2007.

Name	Age	Position
Fred J. Fowler	62	President and Chief Executive Officer, Director
Martha B. Wyrsch	50	President and Chief Executive Officer Spectra Energy Transmission, Director
Gregory L. Ebel	43	Group Executive and Chief Financial Officer
William S. Garner, Jr.	58	Group Executive, General Counsel and Secretary
Alan N. Harris	54	Group Executive and Chief Development Officer
Allen C. Capps	37	Vice President and Treasurer
Sabra L. Harrington	45	Vice President and Controller

Fred J. Fowler served as Group Executive and President of Duke Energy Gas from April 2006 until assuming his current position. Prior to then, Mr. Fowler served as President and Chief Operating Officer of Duke Energy Corporation (Duke Energy) from November 2002 until April 2006. Mr. Fowler serves as Chairman of the Board of Directors of DCP Midstream Partners, LP and is also on the Board of Directors of DCP Midstream, LLC.

Martha B. Wyrsch served as President of Duke Energy Gas Transmission from March 2005 until assuming her current position. Ms. Wyrsch served as Group Vice President and General Counsel of Duke Energy from January 2004 until March 2005. Prior to then, Ms. Wyrsch served in various senior legal roles for Duke Energy. Prior to joining Duke Energy, Ms. Wyrsch served as Vice President, General Counsel and Secretary for KN Energy Inc. from August 1997 until September 1999. Ms. Wyrsch currently serves as Chairman of the Board of Trustees of Spectra Energy Income Fund and Chairman of the Board of Directors of Spectra Energy Partners, LP.

Gregory L. Ebel served as President of Union Gas Limited from January 2005 until assuming his current position. Prior to then, Mr. Ebel served as Vice President, Investor & Shareholder Relations of Duke Energy Corporation from November 2002 until January 2005. Mr. Ebel joined Duke Energy as Managing Director of Mergers and Acquisitions in connection with Duke Energy s acquisition of Westcoast Energy, Inc. He served in that position from March 2002 until November 2002. Mr. Ebel also serves on the Board of Trustees of Spectra Energy Income Fund and on the Board of Directors of DCP Midstream, LLC.

William S. Garner, Jr. served as Group Vice President, Corporate Development of Duke Energy Gas Transmission from March 2006 until assuming his current position. Prior to joining Duke Energy, Mr. Garner served as managing director at Petrie Parkman & Co. (now Merrill Lynch Incorporated), a company which provides investment banking and advisory services to the energy industry and institutional investors. He served in this position from March 2000 until March 2006. Mr. Garner also serves on the Board of Trustees of Spectra Energy Income Fund and on the Board of Directors of Spectra Energy Partners, LP.

Alan N. Harris served as Group Vice President and Chief Financial Officer of Duke Energy Gas Transmission from February 2004 until assuming his current position. Prior to then, Mr. Harris served as Executive Vice President of Duke Energy Gas Transmission from January 2003 until February 2004; Senior Vice President, Strategic Development & Planning, Duke Energy Gas Transmission from March 2002 until January 2003 and Vice President, Controller & Strategic Planning, Duke Energy Gas Transmission from April 1999 until March 2002.

Allen C. Capps served as Director of Finance of EPCO, Inc. from April 2006 until December 2007 before assuming his current position. Prior to then, Mr. Capps served as Interim Controller of TEPPCO Partners, LP

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from June 2005 until April 2006, Director of Technical Accounting and Compliance from April 2004 until June 2005 and Manager of Technical Accounting and Compliance from April 2003 until April 2004. Mr. Capps served as Senior Auditor with Ernst & Young LLP from January 2002 until March 2003.

Sabra L. Harrington served as Vice President, Financial Strategy of Duke Energy Gas Transmission from February 2006 until assuming her current position. Prior to then, Ms. Harrington served as Vice President and Controller of Duke Energy Gas Transmission from August 2003 until February 2006. From March 2002 until August 2003, Ms. Harrington served as Controller of Duke Energy Gas Transmission.

Item 1A. Risk Factors.

Discussed below are the more significant risk factors relating to Spectra Energy.

Reductions in demand for natural gas and low market prices of commodities affect Spectra Energy s operations and cash flows.

Declines in demand for natural gas as a result of economic downturns and conservation efforts in Spectra Energy s gas service territories may reduce overall gas deliveries and reduce Spectra Energy s cash flows, especially if its industrial customers reduce production and, therefore, consumption of gas. Spectra Energy s gas gathering and processing businesses may experience a decline in the volume of natural gas gathered and processed at their plants, resulting in lower revenues and cash flows, as lower economic output reduces energy demand. Revenues and cash flows would also be affected by lower market prices of natural gas and NGLs.

Lower demand for natural gas and lower prices for natural gas and NGLs result from multiple factors that affect the markets where Spectra Energy operates, including:

- weather conditions, including abnormally mild winter or summer weather that cause lower energy usage for heating or cooling purposes, respectively;
- supply of and demand for energy commodities, including any decreases in the production of natural gas which could negatively affect Spectra Energy s processing business due to lower throughput;
- capacity and transmission service into, or out of, Spectra Energy s markets; and
- petrochemical demand for NGLs.

The lack of availability of natural gas resources may cause customers to contract with alternative service providers, which could materially adversely affect Spectra Energy s revenues, earnings and cash flows.

Spectra Energy s natural gas businesses are dependent on the continued availability of natural gas production and reserves. Prices for natural gas, regulatory limitations, or a shift in supply sources could adversely affect development of additional reserves and production that is accessible by Spectra Energy s pipeline, gathering, processing and distribution assets. Lack of commercial quantities of natural gas available to these assets will cause customers to contract with alternative service suppliers, thereby reducing their reliance on Spectra Energy s services, which in turn would materially adversely affect Spectra Energy s revenues, earnings and cash flows.

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Investments and projects located in Canada expose Spectra Energy to fluctuations in currency rates that may adversely affect results of operations and cash flows.

Spectra Energy is exposed to foreign currency risk from investments and operations in Canada. As of December 31, 2007, a 10% devaluation in the currency exchange rate of the Canadian dollar would result in an estimated loss on the translation of Canadian currency earnings of $31 million. The consolidated balance sheet would be negatively affected by $511 million currency translation through the cumulative translation adjustment in accumulated other comprehensive income.

Natural gas gathering and processing operations are subject to commodity price risk which could result in losses in earnings and reduced cash flows.

Spectra Energy has gathering and processing operations that consist of contracts to buy and sell commodities, including contracts for natural gas, NGLs and other commodities that are settled by the delivery of the commodity or cash. Spectra Energy is primarily exposed to market price fluctuations of NGL prices in the Field Services segment and to frac-spreads in the Empress operations in Canada. Since NGL prices historically track crude oil prices, Spectra Energy discloses its NGL price sensitivities in terms of crude oil price changes. Based on a sensitivity analysis as of December 31, 2007, at Spectra Energy s forecasted NGL-to-oil price relationships, a $10 per barrel move in oil prices would affect Spectra Energy s annual pre-tax earnings by approximately $135 million in 2008 ($120 million from Field Services and $15 million from U.S. Transmission). With respect to the frac-spread risk related to Empress processing and NGL marketing activities in Western Canada, as of December 31, 2007, a $0.50 change in the difference between the btu-equivalent price of propane (used as a proxy for Empress NGL production) and the price of natural gas in Alberta, Canada would affect Spectra Energy s pre-tax earnings by approximately $16 million on an annual basis in 2008. These hypothetical calculations consider estimated production levels, but do not consider other potential effects that might result from such changes in commodity prices. The actual effect of commodity price changes on Spectra Energy s earnings could be significantly different than these estimates.

Spectra Energy s business is subject to extensive regulation that affects operations and costs.

Spectra Energy s U.S. assets and operations are subject to regulation by federal, state and local authorities, including regulation by the FERC and by various authorities under federal, state and local environmental laws. Spectra Energy s natural gas assets and operations in Canada are also subject to regulation by federal, provincial and local authorities including the NEB and the OEB and by various federal and provincial authorities under environmental laws. Regulation affects almost every aspect of Spectra Energy s business, including, among other things, the ability to determine terms and rates for services provided by some of its businesses, make acquisitions, construct, expand and operate facilities, issue equity or debt securities, and pay dividends.

In addition, regulators in both the U.S. and Canada have taken actions to strengthen market forces in the gas pipeline industry, which have led to increased competition. In a number of key markets, natural gas pipeline and storage operators are facing competitive pressure from a number of new industry participants, such as alternative suppliers as well as traditional pipeline competitors. Increased competition driven by regulatory changes could have a material effect on Spectra Energy s business, earnings, financial condition and cash flows.

Execution of Spectra Energy s capital projects subjects Spectra Energy to construction risks, increases in labor costs and materials, and other risks that may adversely affect financial results.

A significant portion of Spectra Energy s growth is accomplished through the construction of new pipelines and storage facilities as well as the expansion of existing facilities. Construction of these facilities is subject to various regulatory, development and operational risks, including:

- the ability to obtain necessary approvals and permits by regulatory agencies on a timely basis and on acceptable terms
- the availability of skilled labor, equipment, and materials to complete expansion projects;

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potential changes in federal, state and local statutes and regulations, including environmental requirements, that prevent a project from proceeding or increase the anticipated cost of the project,

impediments on Spectra Energy s ability to acquire rights-of-way or land rights on a timely basis and on acceptable terms; and

the ability to construct projects within anticipated costs, including the risk of cost overruns resulting from inflation or increased costs of equipment, materials, labor, or other factors beyond Spectra Energy s control, that may be material.

Any of these risks could prevent a project from proceeding, delay its completion or increase its anticipated costs. As a result, new facilities may not achieve expected investment return, which could adversely affect results of operations, financial position or cash flows.

Transmission and storage, distribution, and gathering and processing activities involve numerous risks that may result in accidents or otherwise affect operations.

There are a variety of hazards and operating risks inherent in natural gas transmission and storage, distribution, and gathering and processing activities, such as leaks, explosions and mechanical problems that could cause substantial financial losses. In addition, these risks could result in significant injury, loss of human life, significant damage to property, environmental pollution, and impairment of operations, any of which could result in substantial losses to Spectra Energy. For pipeline and storage assets located near populated areas, including residential areas, commercial business centers, industrial sites and other public gathering areas, the level of damage resulting from these risks could be greater. Spectra Energy does not maintain insurance coverage against all of these risks and losses, and any insurance coverage it might maintain may not fully cover the damages caused by those risks and losses. Therefore, should any of these risks materialize, it could have a material adverse effect on Spectra Energy s business, earnings, financial condition and cash flows.

Spectra Energy is subject to numerous environmental laws and regulations, compliance with which requires significant capital expenditures, can increase cost of operations, and may affect or limit business plans, or expose Spectra Energy to environmental liabilities.

Spectra Energy is subject to numerous environmental laws and regulations affecting many aspects of its present and future operations, including air 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 Spectra 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 cleanup 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. Spectra Energy may not be able to obtain or maintain from time to time all required environmental regulatory approvals for its operating assets or development projects. If there is a delay in obtaining any required environmental regulatory approvals, if Spectra Energy fails to obtain or comply with them or if environmental laws or regulations change and become more stringent, the operation of facilities or the development of new facilities could be prevented, delayed or become subject to additional costs. No assurance can be made that the costs that will be incurred to comply with environmental regulations in the future will not have a material effect.

Canada is a signatory to and has ratified the Kyoto Protocol to the United Nations Framework Convention on Climate Change. In 2007, the Province of Alberta adopted legislation which require existing large emitters (facilities releasing 100,000 tons or more of GHG emissions annually) to reduce their annual emissions intensity by 12% beginning July 1, 2007. The effect of this Alberta legislation did not materially affect consolidated results of operations, financial position or cash flows. Should the federal and provincial governments in Canada implement programs to reduce greenhouse gas emissions, Spectra Energy s businesses in

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Canada may be obligated to reduce emissions, purchase emission credits and/or pay a tax on carbon emissions. Due to the substantial uncertainty regarding what additional plans, if any, federal and provincial governments in Canada will implement and whether these plans will apply to Spectra Energy s facilities, Spectra Energy cannot estimate the potential effects of greenhouse gas regulation in Canada on business, earnings, financial condition and cash flows.

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

Spectra Energy is subject to numerous legal proceedings. Litigation is subject to many uncertainties, and Spectra 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 Spectra Energy is involved could require 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 cash flows and results of operations.

Spectra Energy relies on access to short-term money markets and longer-term capital markets to finance capital requirements and support liquidity needs, and access to those markets can be adversely affected, particularly if Spectra Energy or its rated subsidiaries are unable to maintain an investment-grade credit rating, which could adversely affect cash flows or restrict business.

Spectra Energy s business is financed to a large degree through debt. The maturity and repayment profile of debt used to finance investments often does not correlate to cash flows from assets. Accordingly, Spectra 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 operations and to fund investments originally financed through debt. Spectra Energy s senior unsecured long-term debt is currently rated investment-grade by various rating agencies. If the rating agencies were to rate Spectra Energy or its rated subsidiaries below investment-grade, such 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 could decrease.

Spectra Energy maintains revolving credit facilities to provide for borrowings, 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 affiliates to immediately pay down any outstanding drawn amounts under other revolving credit agreements which could adversely affect cash flow or restrict businesses. Furthermore, if Spectra Energy s short-term debt rating were to be below tier 2 (e.g. A-2/P-2, S&P and Moody s, respectively), access to the commercial paper market could be significantly limited.

If Spectra Energy is not able to access capital at competitive rates, its ability to finance operations and implement its strategy may be adversely affected. Restrictions on Spectra Energy s ability to access financial markets may also affect its ability to execute its business plan as scheduled. An inability to access capital may limit Spectra Energy s ability to pursue improvements or acquisitions that it may otherwise rely on for future growth. Any downgrade or other event negatively affecting the credit ratings of Spectra Energy s subsidiaries could make their costs of borrowing higher or access to funding sources more limited, which in turn could increase Spectra 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.

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Spectra Energy may be unable to secure long-term transportation agreements, which could expose transportation volumes and revenues to increased volatility.

In the future, Spectra Energy may be unable to secure long-term transportation agreements for its gas transmission business as a result of economic factors, lack of commercial gas supply to its systems, increased competition, or changes in regulation. Without long-term transportation agreements, Spectra Energy s revenues and contract volumes will be exposed to increased volatility. The inability to secure these agreements would materially adversely affect business, earnings, financial condition or cash flows.

Market based natural gas storage operations are subject to commodity price volatility which could result in variability in earnings and cash flows.

Spectra Energy has market based rates for some of its storage operations and sells its storage services based on natural gas market spreads and volatility.

If natural gas market spreads or volatility deviate from historical norms or there is significant growth in the amount of storage capacity available to natural gas markets, Spectra Energy s approach to managing its market based storage contract portfolio may not protect it from significant variations in storage revenues.

Native land claims have been asserted in British Columbia and Alberta which could affect future access to public lands, the success of which claims could have a significant adverse affect on Spectra Energy s natural gas production and processing.

Certain aboriginal groups have claimed aboriginal and treaty rights over a substantial portion of public lands on which Spectra Energy s facilities in British Columbia and Alberta, and the gas supply areas served by those facilities, are located. The existence of these claims, which range from the assertion of rights of limited use to aboriginal title, has given rise to some uncertainty regarding access to public lands for future development purposes. Such claims, if successful, could have a significant adverse effect on natural gas production in British Columbia and Alberta which could have a material adverse effect on the volume of natural gas processed at Spectra Energy s facilities and of NGLs and other products transported in the associated pipelines. Spectra Energy cannot predict the outcome of these claims or the effect they may ultimately have on business and operations.

Protecting against potential terrorist activities requires significant capital expenditures and a successful terrorist attack could adversely affect Spectra Energy s business.

Acts of terrorism and any possible reprisals as a consequence of any action by the United States and its allies could be directed against companies operating in the United States. This risk is particularly great for companies, like Spectra Energy, operating in any energy infrastructure industry that handles volatile gaseous and liquid hydrocarbons. The potential for terrorism has subjected Spectra Energy s operations to increased risks that could have a material adverse effect on business. In particular, Spectra Energy may experience increased capital and operating costs to implement increased security for its facilities and pipelines, such as additional physical facility and pipeline security and additional security personnel. Moreover, any physical damage to high profile facilities resulting from acts of terrorism may not be covered, or covered fully, by insurance. Spectra Energy may be required to expend material amounts of capital to repair any facilities, the expenditure of which could adversely affect cash flow and business.

Due to changes in Canadian tax laws, Spectra Energy may not be able to fully realize its goal of utilizing tax-efficient structures to improve its cost of capital, optimize returns on assets and finance portfolio growth.

Spectra Energy s business strategy includes utilizing tax-efficient structures, such as master limited partnerships (MLPs) and Canadian income trusts. While the tax treatment for MLPs has not changed, on

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October 31, 2006, the Minister of Finance of Canada announced changes to the income tax treatment of flow-through entities in Canada, including income trusts. Legislation has now been enacted whereby income trusts will be subject to tax at corporate rates on the taxable portion of their distributions. Further, unitholders will be treated as if they have received a dividend equal to the taxable portion of their distributions, and will be taxed accordingly. These proposed changes will generally apply beginning in the 2007 taxation year for trusts that begin to be publicly-traded after October 2006, but would only apply beginning with the 2011 taxation year to those income trusts, such as the Income Fund, that were already publicly traded at the time of the announcement. Such changes could have an adverse effect on Spectra Energy s ability to fully implement its business strategy which may affect its access to capital and the ability to maximize returns on the assets it might hold, and result in an inability to finance portfolio growth through the use of this vehicle.

Spectra Energy might not be able to engage in desirable strategic transactions and equity issuances as a result of its separation from Duke Energy.

To preserve the tax-free treatment to Duke Energy of the distribution of Spectra Energy to the shareholders of Duke Energy, under the Tax Matters agreement that Spectra Energy entered into with Duke Energy, for the two-year period following the distribution, Spectra Energy may be prohibited, except in specified circumstances, from issuing equity securities to satisfy financing needs, acquiring businesses or assets with equity securities, or engaging in other actions or transactions that could jeopardize the tax-free status of the distribution. These restrictions may limit Spectra Energy s ability to pursue strategic transactions or engage in new business or other transactions that may maximize the value of its business.

Poor investment performance of pension plan holdings and other factors affecting pension plan costs could unfavorably affect Spectra Energy s earnings and liquidity.

Spectra 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 Spectra Energy s required or voluntary contributions made to the plans. Without sustained growth in the pension plan investments over time to increase the value of Spectra Energy s plan assets, and depending upon the other factors impacting Spectra Energy s costs as listed above, Spectra Energy could be required to fund its plans with significant amounts of cash. Such cash funding obligations could have a material effect on Spectra Energy s earnings and cash flows.

Item 1B. Unresolved Staff Comments.

None.

Item 2. Properties.

At December 31, 2007, Spectra Energy had over 100 primary facilities located in the United States and Canada. Spectra Energy generally owns sites associated with its major pipeline facilities, such as compressor stations. However, it generally operates its transmission facilities transmission and distribution pipelines using rights of way pursuant to easements to install and operate pipelines but does not own the land. Except as described in Part I, Item 8. Financial Statements and Supplementary Data, Note 16 of Notes to Consolidated Financial Statements, none of Spectra Energy s property was secured by mortgages or other material security interests at December 31, 2007.

Spectra Energy s corporate headquarters are located at 5400 Westheimer Court, Houston, Texas 77056, which is a leased facility. The lease expires in April 2018. It also maintains major offices in Calgary, Alberta; Vancouver, British Columbia; Chatham, Ontario; Waltham, Massachusetts; Tampa, Florida; Halifax, Nova

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Scotia; Toronto, Ontario; and Nashville, Tennessee. For a description of its material properties, see Item 1. Business. Spectra Energy s property, plant and equipment includes buildings, technical equipment and other equipment capitalized under capital lease agreements. For more details, refer to Note 14 of Notes to Consolidated Financial Statements.

Item 3. Legal Proceedings.

For information regarding legal proceedings, including regulatory and environmental matters, see Notes 5 and 18 of Notes to Consolidated Financial Statements.

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

At the Spectra Energy Annual Meeting of Shareholders on October 31, 2007, shareholders elected Fred J. Fowler, William T. Esrey, Dennis R. Hendrix and Pamela L. Carter to serve as Class I directors until the 2010 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
Fred J. Fowler	538,175,938	12,389,427
William T. Esrey	537,874,976	12,690,388
Dennis R. Hendrix	537,879,554	12,685,810
Pamela L. Carter	537,968,930	12,596,434

In addition, shareholders at the meeting also ratified the selection of Deloitte & Touche LLP to act as independent registered public accounting firm for Spectra Energy for 2007. There were 539,242,135 shares voted for the proposal, 6,642,193 shares voted against the proposal and 4,680,734 shares abstained.

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PART II

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

Spectra Energy s common stock is traded on the New York Stock Exchange under the symbol SE. As of February 19, 2008, there were 151,415 holders of record of Spectra Energy s common stock and 525,281 beneficial owners. There was no market for Spectra Energy s common stock in 2006 because all of the outstanding shares of common stock of Spectra Energy were owned by Duke Energy.

Common Stock Data by Quarter

2007	Dividends Per Common Share	Stock Price Range(a) High	Low
First Quarter	$ 0.22	$ 30.00	$ 23.55
Second Quarter	$ 0.22	$ 27.34	$ 24.89
Third Quarter	$ 0.22	$ 27.73	$ 21.24
Fourth Quarter	$ 0.22	$ 26.34	$ 23.98

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

Spectra Energy did not pay any cash dividends in 2006. Currently, Spectra Energy anticipates a dividend payout ratio of approximately 60% of its anticipated annual net income per share of common stock. The declaration and payment of dividends by Spectra Energy will be subject to the sole discretion of the board of directors and will depend upon many factors, including Spectra Energy s financial condition, earnings, capital requirements of its operating subsidiaries, covenants associated with certain of its debt obligations, legal requirements, regulatory constraints and other factors deemed relevant by the board of directors. Spectra Energy anticipates increasing its dividend in an amount consistent with underlying growth in earnings. On January 4, 2008, Spectra Energy increased its quarterly dividend to $0.23 per common share.

Unregistered Sales

In connection with Spectra Energy s incorporation on July 28, 2006, Spectra Energy issued to Duke Energy 1,000 shares of Spectra Energy s common stock, par value $.001 per share, in exchange for a $1.00 contribution. The issuance of such shares of Spectra Energy common stock to Duke Energy was exempt from registration under Section 4(2) of the Securities Act of 1934, as amended. There were no sales of unregistered equity securities during 2007.

Market Repurchases

Spectra Energy has not made any repurchases of shares of its common stock.

Item 6. Selected Financial Data.

The following selected financial data should be read in conjunction with Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations and Item 8. Financial Statement and Supplemental Data.

On January 2, 2007, Duke Energy completed the spin-off of its natural gas businesses, primarily comprised of the Natural Gas Transmission and Field Services business segments of Duke Energy that were owned through Duke Energy s then wholly owned subsidiary, Spectra Capital. Spectra Capital is treated as the predecessor entity

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to Spectra Energy for financial statement reporting purposes. Accordingly, the information presented below for periods prior to 2007 is that of Spectra Capital. This information is not necessarily indicative of future performance or what the financial position and results of operations would have been if Spectra Energy had operated as a separate, stand-alone entity for periods presented prior to 2007.

	2007	2006	2005	2004	2003(b)
	(dollars in millions, except per-share amounts)				
Statements of Operations(a)					
Operating revenues	$ 4,742	$ 4,532	$ 9,454	$ 13,433	$ 11,937
Operating income	1,442	1,245	1,853	1,327	103
Income (loss) from continuing operations	944	936	1,409	(707)	(317)
Net income (loss)	957	1,244	674	(114)	(1,858)
Ratio of Earnings to Fixed Charges	3.1	3.1	4.3(c)	1.7	(d)
Common Stock Data					
Earnings per share from continuing operations					
Basic and Diluted	$ 1.49	n/a	n/a	n/a	n/a
Earnings per share total					
Basic and Diluted	1.51	n/a	n/a	n/a	n/a
Dividends per share	0.88	n/a	n/a	n/a	n/a

	2007	2006	December 31, 2005	2004	2003(c)
Balance Sheet					
Total assets	$ 22,970	$ 20,345	$ 35,056	$ 37,183	$ 39,892
Long-term debt including capital leases, less current maturities	8,345	7,726	8,790	11,288	13,655

(a) Significant transactions reflected in the results include: the transfer of certain businesses to Duke Energy in December 2006 (see Item 8. Financial Statements and Supplementary Data, Note 1 of Notes to Consolidated Financial Statements), the 2006 transfer of DENA Midwestern assets to Duke Energy Ohio (see Note 9), the Crescent joint venture transaction and subsequent deconsolidation effective September 7, 2006 (see Note 9), the 2005 DENA disposition (see Note 9), the deconsolidation of DCP Midstream effective July 1, 2005 (see Note 3), the 2005 DCP Midstream sale of TEPPCO (see Note 3), a $1,030 million 2004 tax charge as a result of a reorganization relating to Duke Energy Americas, LLC, a $360 million pre-tax loss on the 2004 DENA sale of the Southeast plants and $2.8 billion of pre-tax charges related to DENA asset impairments in 2003.

(b) As of January 1, 2003, Spectra 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, and Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations. In accordance with the transition guidance for these standards, Spectra Energy recorded a net-of-tax and minority interest cumulative effect adjustment totaling $133 million for changes in accounting principles.

(c) 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 3).

(d) Earnings were inadequate to cover fixed charges by $500 million in 2003.

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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 Item 8. Financial Statements and Supplementary Data.

EXECUTIVE OVERVIEW

2007 was a significant year for Spectra Energy, beginning with the spin-off from Duke Energy that was effective on January 2, 2007 allowing Spectra Energy to benefit from a sharper focus on core natural gas businesses and growth opportunities, with greater flexibility in accessing capital markets and responding to changes in the industry. Throughout 2007, Spectra Energy successfully performed on the strategies and objectives outlined to shareholders and the activities required to create and sustain a new, stand-alone corporate structure.

Spectra Energy reported net income of $957 million, and $1.51 of earnings per share for 2007, exceeding the employee incentive target earnings per share, primarily as a result of strong revenues for all Spectra Energy segments, including the effects of strong commodity prices for the Field Services and Empress operations. These positive results demonstrated the ability to capitalize on existing assets and to continue developing operational efficiencies. Expansion capital and investment expenditures for 2007 were $1.50 billion. These investments in Spectra Energy s assets delivered on the organic growth and expansion activity discussed throughout the year as a key initiative for Spectra Energy. About $650 million of expansion projects were placed into service during the year, contributing to earnings growth in 2007 and beyond.

Another significant event was the formation and initial public offering in July 2007 of Spectra Partners, a newly formed midstream energy master limited partnership. Spectra Partners is a separate, publicly traded entity in which Spectra Energy retains an 83% interest. This transaction provided proceeds to Spectra Energy and will provide additional flexibility and growth options going forward.

Spectra Energy s Strategy. Spectra Energy s primary business objective is to provide value-added, reliable and safe services to customers, which Spectra Energy believes will create opportunities to deliver increased earnings and dividends per share and value to shareholders of Spectra Energy. Spectra Energy intends to accomplish this objective by executing the following overall business strategies:

Deliver on 2008 financial commitments.

Enhance and solidify Spectra Energy s profile and position as a premier natural gas infrastructure company.

Aggressively develop new opportunities and projects that add long-term shareholder value.

Enhance core competencies of customer service, reliability, cost management and compliance.

Build on the high-performance culture by focusing on safety, diversity, inclusion, leadership and employee development.

Focus on the future. Spectra Energy must be able to quickly change course when opportunities present themselves in order to be the effective and proactive partner that Spectra Energy s customers expect and the industry leader that Spectra Energy aspires to be.

Through the continued execution of these strategies, Spectra Energy expects to grow and strengthen the overall business, capture new growth opportunities and deliver value to Spectra Energy s stakeholders.

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Spin-off from Duke Energy. On January 2, 2007, Duke Energy completed the spin-off of Spectra Energy. Duke Energy contributed its natural gas businesses, primarily comprised of the Natural Gas Transmission and Field Services business segments of Duke Energy that were owned through Duke Energy s then wholly owned subsidiary, Spectra Capital. Duke Energy contributed its ownership interests in Spectra Capital to Spectra Energy and all of the outstanding common stock of Spectra Energy was distributed to Duke Energy s shareholders. Duke Energy s shareholders received one share of Spectra Energy common stock for every two shares of Duke Energy common stock, resulting in the issuance of approximately 631 million shares of Spectra Energy on January 2, 2007.

Prior to the distribution by Duke Energy, Spectra Capital implemented an internal reorganization in which the operations and assets of Spectra Capital that were not associated with the natural gas businesses were contributed by Spectra Capital to Duke Energy or its subsidiaries. The contribution to Duke Energy included the International Energy business segment, Crescent Resources (a real estate business), the remaining portion of Spectra Capital s business formerly known as DENA (Duke Energy North America), and other miscellaneous operations.

Following this internal reorganization and the distribution by Duke Energy to Spectra Energy, Spectra Capital became a direct, wholly owned subsidiary of Spectra Energy. All of the operating assets, liabilities and operations of Spectra Energy are held by Spectra Capital, except for employee benefit plan assets and liabilities that were contributed by Duke Energy directly to Spectra Energy in the separation transaction. As a result of these spin-off steps, Spectra Capital is treated as the predecessor entity of Spectra Energy for financial statement reporting purposes.

The results of operations of substantially all of the businesses retained by Duke Energy are reflected as discontinued operations in the accompanying Consolidated Statements of Operations for 2006 and 2005. Transferred corporate services entities remain presented within continuing operations.

Effective upon the completion of the spin-off, Spectra Energy adopted new business segments to align the various operations of Spectra Energy with how the chief operating decision maker views the business: U.S. Transmission, Distribution, Western Canada Transmission & Processing and Field Services. All 2006 and 2005 information discussed herein has been re-cast to reflect these new business segments.

2007 Financial Results. Spectra Energy reported income from continuing operations of $944 million in 2007 compared to income from continuing operations of $936 million in 2006. The increase in income from continuing operations reflects higher earnings from the U.S. Transmission, Distribution and Western Canada Transmission & Processing operations, partly offset by higher interest expense and a higher effective tax rate. Highlights for 2007 include the following:

- U.S. Transmission s earnings increased primarily as a result of strong revenues from pipeline and storage services and earnings associated with expansion and development projects;

- Distribution results benefited from increased distribution margins, favorable storage market conditions and a strengthening Canadian dollar, partially offset by higher operating costs;

- Western Canada Transmission & Processing s earnings increased primarily as a result of very strong earnings at the Empress processing plant attributable to higher NGL prices and Canadian dollar exchange impacts, partially offset by declines in the BC Pipes and Field Services operations;

- Field Services benefited from extremely strong NGL prices compared to 2006, especially in the fourth quarter; however, these commodity price benefits were offset by lower gathering and processing margins, higher operating costs and 2007 derivative losses at DCP Midstream Partners, LP (DCP Partners), a publicly traded MLP which is owned 35.4% by DCP Midstream; and

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Income From Discontinued Operations in the 2006 period was primarily composed of a gain on the sale of the 50% ownership interest in Crescent and net earnings from businesses transferred to Duke Energy prior to the spin-off.

Significant Economic Factors for Spectra Energy s Business. Spectra Energy s regulated businesses are generally economically stable and are not significantly affected in the long-term by seasonal temperature variations and changing commodity prices. However, all of Spectra Energy s businesses can be negatively affected in the long term by sustained downturns or sluggishness in the economy, which could affect long-term demand and market prices for natural gas and NGLs, all of which are beyond Spectra Energy s control and could impair the ability to meet long-term goals.

Most of Spectra Energy s revenues are based on regulated tariff rates, which include the recovery of certain fuel costs. However, lower overall economic output would cause a decline in the volume of natural gas transported and distributed or gathered and processed at Spectra Energy s plants, resulting in lower earnings and cash flows. This decline would primarily affect distribution revenues in the short term. Transmission revenues could be affected by long-term economic declines that could result in the non-renewal of long-term contracts at time of expiration. Pipeline transportation and storage customers continue to renew most contracts as they expire. Processing revenues are also affected by volumes of natural gas made available to the system, which is primarily driven by levels of natural gas drilling activity. Since late 2006, a reduction in Western Canadian drilling has occurred when compared to levels generally experienced during the previous three years. Overall, exploration and development activity in Spectra s Western Canadian area has been relatively steady with increased activity around Spectra Energy s McMahon and Pine River plants, and a decline in the Fort Nelson area of Northeast British Columbia.

Spectra Energy s key markets the Northeast United States, Florida and the Southeast United States, Ontario and the Pacific Northwest are projected to continue to exhibit higher than average annual growth in natural gas demand versus the North American and U.S. Lower 48 average growth rates through 2015. This demand growth is primarily driven by the natural gas-fired electric generation sector. The natural gas industry is currently experiencing a significant shift in the sources of supply, and this dramatic change is affecting Spectra Energy s growth strategies. Traditionally, supply to Spectra Energy s markets has come from the Gulf Coast region, onshore and offshore, as well as from fields in Western Canada and Eastern Canada. The national supply profile is shifting to new sources of gas from basins in the Rockies, Mid-Continent and East Texas. In addition, the natural gas supply outlook will be shaped by new LNG re-gasification facilities being built. LNG will clearly be an important new source of supply, but the timing and extent of incremental supply from LNG is yet to be determined and, at present, LNG remains a small percentage of the overall supply to the markets Spectra Energy serves. These supply shifts are shaping the growth strategies that Spectra Energy will pursue, and therefore, will affect the nature of the projects anticipated in the capital and investment expenditure increases discussed below in Liquidity and Capital Resources.

Spectra Energy s businesses in the U.S. are subject to regulations on the federal and state level. Regulations, applicable to the gas transmission and storage industry, have a significant effect on the nature of the businesses and the manner in which they operate. Changes to regulations are ongoing and Spectra 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. Additionally, investments and projects located in Canada expose Spectra Energy to risks related to Canadian laws, taxes, economic conditions, fluctuations in currency rates, political conditions and policies of the Canadian government. From 2002 through 2007, the Canadian dollar strengthened significantly compared to the U.S. dollar, which has favorably affected earnings during these periods. Changes in this exchange rate or other of these factors are difficult to predict and may affect future results.

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Certain of Spectra Energy s earnings are affected by fluctuations in commodity prices, especially the earnings of the DCP Midstream investment and the Empress NGL operations in Canada. Although natural gas and NGL commodity prices increased in 2005, 2006 and 2007, this trend in commodity prices may not be indicative of future prices. Management evaluates, on an ongoing basis, the risks associated with commodity price volatility and currently does not have any plans to enter into hedge positions around these earnings.

It is expected that the effective income tax rates will approximate 30-35% on an annual basis, taking into consideration the United States and Canadian tax jurisdictions applicable to operations.

As Spectra Energy executes on its strategic objectives, expansion expenditures could average more than $1 billion per year over the next few years. Given the anticipated level of capital and investment expenditures in 2008 of approximately $2.4 billion, capital resources will include significant new long-term borrowings of approximately $1.5 billion in 2008. However, as a result of expansion earnings contributions and ongoing strong earnings performance anticipated in the existing operations, Spectra Energy expects to maintain a capital structure and liquidity profile that continues to support an investment-grade credit rating. An inability to access capital at competitive rates could adversely affect Spectra Energy s ability to implement its strategy. Market disruptions, or a downgrade of the credit ratings of Spectra Energy or its subsidiaries may increase the cost of borrowing or adversely affect the ability to access one or more sources of liquidity.

During the past two years, capital expansion projects have been exposed to cost pressures associated with the availability of skilled labor and the pricing of materials. As Spectra Energy moves forward with planned expansion opportunities, there will be continual focus on project management activities to address these pressures. Significant cost increases could negatively affect the returns ultimately earned on current and future expansions.

For further information related to management s assessment of Spectra Energy s risk factors, see Part I, Item 1A. Risk Factors.

RESULTS OF OPERATIONS

	2007	2006	2005
		(in millions)	
Operating revenues	$ 4,742	$ 4,532	$ 9,454
Operating expenses	3,313	3,334	8,123
Gains on sales of other assets and other, net	13	47	522
Operating income	1,442	1,245	1,853
Other income and expenses	649	736	1,668
Interest expense	633	605	675
Minority interest expense	71	45	511
Earnings from continuing operations before income taxes	1,387	1,331	2,335
Income tax expense from continuing operations	443	395	926
Income from continuing operations	944	936	1,409
Income (loss) from discontinued operations, net of tax	13	308	(731)
Income before cumulative effect of change in accounting principle	957	1,244	678
Cumulative effect of change in accounting principle, net of tax and minority interest			(4)
Net income	$ 957	$ 1,244	$ 674

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2007 Compared to 2006

Operating Revenues. The $210 million, or 5%, increase was driven primarily by:

- the effects of the strong Canadian dollar on revenues at Western Canada Transmission & Processing and Distribution, and
- the growth in revenues from higher demand for transmission and storage services and expansion projects.

Operating Expenses. The $21 million decrease was driven primarily by:

- the capitalization of Northeast expansion project costs initially charged to operating expense. Spectra Energy expenses project development costs until such time as recovery of costs is determined to be probable. At that time, these costs are capitalized to property, plant and equipment and operating expenses are reduced,
- a decrease in corporate costs primarily as a result of the reduced portfolio and activity of the U.S. captive insurance entity, partially offset by
- the stronger Canadian dollar in 2007 compared to 2006.

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

Gain on Sales of Other Assets and Other, net. The $34 million decrease was primarily due to the 2006 gains of $28 million on settlements of customers transportation contracts at U.S. Transmission.

Operating Income. The $197 million increase primarily reflects growth in revenues and lower expenses resulting from the net capitalization in 2007 of Northeast expansion project costs.

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

Other Income and Expenses. The $87 million decrease represents lower equity earnings from the Field Services segment and management fees billed by Spectra Energy to certain Duke Energy operations in 2006. These were partially offset by higher equity earnings on joint ventures that resulted primarily from capitalization of previously expensed project development costs.

Interest Expense. The $28 million increase was primarily due to interest costs capitalized in the prior year period related to capital projects of businesses that were transferred to Duke Energy.

Minority Interest Expense. The $26 million increase primarily resulted from higher earnings on Maritimes and Northeast pipeline, the formation in July 2007 of Spectra Partners and a decrease in the ownership of the operations of the Income Fund in the third quarter of 2006.

Income Tax Expense from Continuing Operations. The $48 million increase was a result of higher earnings from continuing operations in 2007 and tax benefits recorded in 2006. The effective tax rate was 32.0% for 2007 compared to 29.7% for the same period in 2006. The lower effective tax rate in 2006 resulted from a reduction in the unitary state tax rate as a result of Duke Energy s merger with Cinergy Corp (Cinergy) and a 2006 tax benefit related to the impairment of an international investment no longer owned by Spectra Energy.

Income from Discontinued Operations, net of tax. Income from discontinued operations, net of tax was $13 million for 2007 and $308 million for 2006. These amounts represent results of operations and gains (losses) on dispositions related primarily to DENA s assets and contracts outside the Midwestern and Southeastern

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United States, which are included in Other, as well as the operations of International Energy and Spectra Energy s effective 50% interest in Crescent, and a number of businesses previously included in Other, which are classified in discontinued operations as a result of Spectra Energy transferring these businesses to Duke Energy in December 2006.

2006 Compared to 2005

Operating Revenues. The $4,922 million decrease was driven by the deconsolidation of DCP Midstream, effective July 1, 2005, which resulted from the transfer of a 19.7% interest in DCP Midstream to ConocoPhillips. This impact reduced reported revenues by $5,530 million. The remaining $608 million increase in revenues resulted from:

- the Empress System acquired in August 2005,
- favorable Canadian dollar exchange impacts; and
- 2005 mark-to-market losses resulting from increased commodity prices associated with cash flow hedges that hedged Field Services commodity price risk for a portion of 2005.

Operating Expenses. The $4,789 million decrease was primarily driven by the $5,090 million decrease due to the deconsolidation of DCP Midstream, effective July 1, 2005. The remaining increase of $301 million resulted primarily from:

- the Empress System that was acquired in August 2005,
- favorable Canadian dollar exchange impacts, and
- higher pipeline and storage operating costs, increased pipeline integrity and project development expenses, and higher corporate costs allocated from Duke Energy to the U.S. Transmission segment, partially offset by
- a decrease in captive insurance expenses due primarily to the transfer of ownership in Bison to Duke Energy effective April 1, 2006, and prior year recognition of reserves for estimated property damage related to hurricanes and business interruption losses, and
- a decrease associated with the 2005 recognition of unrealized losses as a result of the discontinuance of certain cash flow hedges entered into to hedge Field Services commodity price risk.

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

Gain on Sales of Other Assets and Other, net. The $475 million decrease was primarily due to the $575 million pre-tax gain resulting from the DCP Midstream disposition transaction, partially offset by $70 million of net pre-tax losses at Commercial Power, principally the termination of structured power contracts in the Southeast region.

Operating Income. The $608 million decrease was primarily related to the $575 million gain in 2005 resulting from the DCP Midstream disposition transaction and the effects of the deconsolidation of DCP Midstream, effective July 1, 2005, which amounted to $440 million for 2005. Partially offsetting these decreases were a $250 million negative effect to operating income in 2005 related to the discontinuance of certain cash flow hedges entered into to hedge Field Services commodity price risk and a $70 million charge in 2005 related to the termination of

former DENA structured power contracts in the Southeast region.

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

Other Income and Expenses. The $932 million decrease was due primarily to $1,245 million of pre-tax gains on sales of equity investments recorded in 2005, primarily associated with the sale of TEPPCO GP and Spectra Energy s limited partner interest in TEPPCO LP, partially offset by an increase in equity in earnings of unconsolidated affiliates due primarily to the deconsolidation of DCP Midstream effective July 1, 2005.

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Interest Expense. The $70 million decrease was primarily attributable to reduced interest expense associated with DCP Midstream, which was deconsolidated on July 1, 2005.

Minority Interest Expense. The $466 million decrease primarily resulted from the 2005 gain associated with the sale of TEPPCO GP and the effect of deconsolidation of DCP Midstream effective July 1, 2005.

Income Tax Expense from Continuing Operations. The $531 million decrease primarily resulted from lower pre-tax earnings, due primarily to the 2005 gains associated with the sale of TEPPCO GP and Spectra Energy s limited partner interest in TEPPCO LP as discussed above. In addition, the effective tax rate decreased to 29.7% in 2006 from 39.7% in 2005. The lower effective tax rate in 2006 compared to 2005 resulted primarily from a 2006 benefit of $30 million due to a reduction in the unitary state tax rate as a result of Duke Energy s merger with Cinergy, a 2006 tax benefit of $25 million related to the impairment of an investment in Bolivia and a 2005 tax expense related to the repatriation of foreign earnings.

Income (Loss) from Discontinued Operations, net of tax. Income (loss) from discontinued operations, net of tax was $308 million for 2006 and ($731) million for 2005. These amounts represent results of operations and gains (losses) on dispositions related primarily to DENA s assets and contracts outside the Midwestern and Southeastern United States, which are included in Other, as well as the operations of International Energy and Spectra Energy s effective 50% interest in Crescent, and a number of businesses previously included in Other, which are classified in discontinued operations as a result of Spectra Energy transferring these businesses to Duke Energy in December 2006.

The 2005 amount is primarily comprised of a $740 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 DENA s remaining assets and contracts outside the Midwestern United States and certain contractual positions related to the Midwestern assets. Additionally, during 2005, Spectra Energy recognized after-tax losses of $330 million (approximately $400 million pre-tax) as the result of selling certain gas transportation and structured contracts related to DENA operations. These charges were offset by the recognition of after-tax gains of $160 million (approximately $200 million pre-tax) related to discontinued cash flow hedges associated with DENA operations and the net favorable operations of International Energy and Spectra Energy s effective 50% interest in Crescent, and a number of businesses previously included in Other.

Cumulative Effect of Change in Accounting Principle, net of tax and minority interest. During 2005, Spectra 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 Financial Accounting Standards Board (FASB) Interpretation (FIN) No. 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 Spectra 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 investments are managed centrally by Spectra 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 Spectra Energy s ownership interest in operations without regard to financing methods or capital structures.

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As previously discussed, as a result of the reorganization and spin-off of Spectra Energy from Duke Energy, Spectra Energy now manages its business in four reportable segments: U.S. Transmission, Distribution, Western Canada Transmission & Processing and Field Services. The remainder of Spectra Energy s business operations is presented as Other, and consists of unallocated corporate costs, wholly owned captive insurance subsidiaries, employee benefit plan assets and liabilities, and other miscellaneous activities. Comparative 2006 and 2005 data has been re-cast to conform the business segment disclosures to the new segment structure.

U.S. Transmission provides transportation and storage of natural gas for customers in various regions of the Eastern and Southeastern United States and the Maritime Provinces in Canada.

Distribution provides retail natural gas distribution service in Ontario, Canada, as well as natural gas transportation and storage services to other utilities and energy market participants in Ontario, Quebec and the United States.

Western Canada Transmission & Processing provides transportation of natural gas, natural gas gathering and processing services, and NGL extraction, fractionation, transportation, storage and marketing to customers in Western Canada and the northern tier of the United States.

Field Services gathers and processes natural gas, and fractionates, markets and trades NGLs. It conducts operations through DCP Midstream, which is owned 50% by Spectra Energy and 50% by ConocoPhillips. Field Services gathers raw natural gas through gathering systems located in eight major natural gas producing regions: Permian Basin, Mid-Continent, Rocky Mountain, East Texas-North Louisiana, Barnett Shale, Gulf Coast, South Texas and Central Texas.

Spectra 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

	2007	2006	2005
		(in millions)	
U.S. Transmission	$ 894	$ 816	$ 840
Distribution	322	265	277
Western Canada Transmission & Processing	366	345	243
Field Services(a)	533	569	1,946
Commercial Power(b)			(70)
Total reportable segment EBIT	2,115	1,995	3,236
Other	(112)	(77)	(250)
Total reportable segment and other EBIT	2,003	1,918	2,986
Interest expense	(633)	(605)	(675)
Interest income and other(c)	17	18	24
Consolidated earnings from continuing operations before income taxes	$ 1,387	$ 1,331	$ 2,335

(a) In July 2005, the ownership interest in DCP Midstream was reduced from 69.7% to 50%. Field Services segment data reflects DCP Midstream as a consolidated entity for periods prior to July 1, 2005 and an equity method investment for periods after June 30, 2005.
(b) Reflects amounts associated with DENA s sale of structured power contracts in December 2005. Commercial Power is not a current business segment of Spectra Energy.
(c) Other includes foreign currency transaction gains and losses and additional minority interest expense not allocated to the segment results.

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Minority interest expense as presented in the following segment-level discussions includes only minority interest expense related to EBIT of non-wholly owned entities. It does not include minority interest expense related to interest and taxes of those operations. The amounts discussed below include intercompany transactions that are eliminated in the consolidated financial statements.

U.S. Transmission

	2007	2006	Increase (Decrease)	2005	Increase (Decrease)
	(in millions, except where noted)				
Operating revenues	$ 1,540	$ 1,503	$ 37	$ 1,453	$ 50
Operating expenses					
Operating, maintenance and other	473	544	(71)	431	113
Depreciation and amortization	217	203	14	207	(4)
Gains on sales of other assets and other, net	8	44	(36)	6	38
Operating income	858	800	58	821	(21)
Other income and expenses, net	85	44	41	47	(3)
Minority interest expense	49	28	21	28	
EBIT	$ 894	$ 816	$ 78	$ 840	$ (24)
Proportional throughput, TBtu(a)	2,202	1,930	272	1,953	(23)

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

2007 Compared to 2006

Operating Revenues. The $37 million increase was driven by:

a $32 million increase from higher demand for pipeline and storage services, primarily attributable to higher volumes and rates on Maritimes and Northeast Pipeline, and

a $21 million increase from expansion projects that were placed in service in 2006 and 2007, partially offset by

a $15 million decrease in processing revenues associated with pipeline operations, primarily from lower volumes compared to the 2006 period when utilization of the facilities was higher than normal due to hurricane effects.

Operating, Maintenance and Other. The $71 million decrease was driven by:

a $41 million decrease in project development costs charged to operations as a result of lower development costs incurred in 2007 and increased capitalization of Northeast expansion project costs in the 2007 period compared to 2006. In 2007, U.S. Transmission recognized a net reduction in operating expenses of $17 million, representing net development costs capitalized during that period, while 2006 included net project development costs of $24 million in operating expenses.

a $14 million decrease in operating costs primarily associated with lower plant processing fees as a result of a renegotiated contract,

a $12 million decrease in ad valorem taxes primarily as a result of favorable property valuations in certain states, and

an $11 million decrease resulting from higher recoveries of pipeline compressor fuel by the East Tennessee pipeline , partially offset by

a $16 million increase from higher labor and outside services costs for pipeline and storage operations.

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Depreciation and Amortization. The $14 million increase was primarily driven by expansion projects placed into service in late 2006 and in 2007, an increase in the depreciation rate on Maritimes and Northeast Pipeline as part of a negotiated toll settlement that was effective on January 1, 2007, and Canadian dollar exchange effects on Maritimes and Northeast Pipeline (Canada) depreciation.

Gains on Sales of Other Assets and Other, net. The $36 million decrease was primarily due to a $28 million gain on the settlement of a customer s transportation contracts in 2006.

Other Income and Expenses, net. The $41 million increase was a result of higher equity earnings from unconsolidated affiliates primarily attributable to the capitalization of project development costs for the Southeast Supply Header (SESH) and Gulfstream Phase IV projects.

Minority Interest Expense. The $21 million increase was driven primarily by higher revenues on Maritimes & Northeast Pipeline and earnings from Spectra Partners formed in July 2007.

EBIT. The $78 million increase was primarily due to strong revenues in all pipeline and storage businesses attributable to high demand for services, increased revenues from in-service expansion projects, and the capitalization of previously expensed development costs, partially offset by a gain on the settlement of a customer s transportation contracts in 2006.

2006 Compared to 2005

Operating Revenues. The $50 million increase was driven by:

- a $27 million increase in processing revenues resulting from higher prices and volumes associated with hurricane activities, partially offset by lower transportation and storage revenues primarily from lower negotiated rates in 2006 and 2005 contract settlements, and
- a $26 million increase from expansion projects primarily from the acquisition of the remaining 50% interest in Saltville in August 2005.

Operating, Maintenance and Other. The $113 million increase was driven by:

- a $35 million increase primarily related to higher labor and outside service costs for pipeline and storage operations,
- a $31 million increase in corporate costs allocations from Duke Energy, primarily as a result of the completion in 2006 of various business reorganizations by Duke Energy, including the merger with Cinergy,
- a $15 million increase in plant processing fees for a new third party arrangement associated with hurricane plant outages,
- a $12 million increase resulting from expansion projects primarily from the acquisition of the remaining 50% interest in Saltville in August 2005,
- a $12 million increase in pipeline integrity expenses that are reflected in operating and maintenance expenses beginning in 2006 as a result of a FERC accounting order to charge such costs to expense, and

an $8 million increase in project development expenses, partially offset by

a $15 million decrease related to the resolution in 2006 of prior tax years ad valorem tax issues.

Gains on Sales of Other Assets and Other, net. The $38 million increase was driven primarily by a $28 million gain in 2006 on the settlement of a customer s transportation contracts and a $5 million gain on the sale of certain gathering assets in 2006.

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EBIT. The $24 million decrease was primarily due to increased operating and maintenance expenses, partially offset by higher revenue resulting from pipeline expansion projects, increased processing revenues associated with transportation and the gain on a settlement of a customer s transportation contract.

Matters Affecting Future U.S. Transmission Results

U.S. Transmission plans to continue earnings growth through capital efficient projects, such as transportation and storage expansion to support a two-pronged supply push / market pull strategy, as well as continued focus on optimizing the performance of the existing operations through organizational efficiencies and cost control. Future earnings growth will be dependent on the success of expansion plans in both the market and supply areas of the pipeline network, the ability to continue renewing service contracts and continued regulatory stability. NGL prices will continue to affect processing revenues that are associated with transportation services.

Distribution

	2007	2006	Increase (Decrease)	2005	Increase (Decrease)
	(in millions, except where noted)				
Operating revenues	$ 1,899	$ 1,822	$ 77	$ 1,725	$ 97
Operating expenses					
Natural gas purchased	1,059	1,091	(32)	1,024	67
Operating, maintenance and other	361	322	39	296	26
Depreciation and amortization	162	144	18	129	15
Gains on sales of other assets and other, net	5		5		
Operating income	322	265	57	276	(11)
Other income and expenses, net				1	(1)
EBIT	$ 322	$ 265	$ 57	$ 277	$ (12)
Number of customers	1,289	1,268	21	1,249	19
Heating degree days	7,070	6,489	581	7,273	(784)
Pipeline throughput, TBtu	844	736	108	849	(113)

2007 Compared to 2006

Operating Revenues. The $77 million increase was driven by:

- a $144 million increase in customer usage of natural gas primarily associated with winter weather that was approximately 9% colder than the previous year,
- a $92 million increase caused by a stronger Canadian dollar,
- a $21 million increase in storage and transmission revenues primarily due to favorable market conditions and growth of the transmission system,
- a $19 million increase due to higher distribution rates approved by the regulator, and

a $12 million increase as a result of an earnings sharing requirement in 2006, partially offset by

a $213 million decrease from lower natural gas prices passed through to customers without a mark-up.

Natural Gas Purchased. The $32 million decrease resulted from:

a $213 million decrease related to lower natural gas prices passed through to customers, partially offset by

a $111 million increase in customer usage of natural gas associated with colder winter weather than the previous year,

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a $49 million increase caused by Canadian dollar exchange effects, and

a $24 million increase related to gas volumes used in operations.

Operating, Maintenance & Other. The $39 million increase was primarily driven by:

a $22 million increase caused by Canadian dollar exchange effects, and

a $13 million increase in labor costs.

Depreciation and Amortization. The $18 million increase was primarily driven by completion of Phase I of the Dawn-Trafalgar transmission system expansion and Canadian dollar exchange effects.

EBIT. The $57 million increase primarily resulted from higher gas distribution margins, favorable storage market conditions and a stronger Canadian dollar, partially offset by higher operating and gas costs.

2006 Compared to 2005

Operating Revenues. The $97 million increase was driven primarily by:

a $146 million increase from higher natural gas prices passed through to customers without a markup,

a $102 million increase caused by Canadian dollar exchange effects,

an $18 million increase as a result of growth in the number of customers, and

a $16 million increase in storage and transmission revenues primarily due to higher storage prices driven by warmer weather, partially offset by

a $186 million decrease primarily resulting from lower gas usage due to warmer weather compared to 2005.

Natural Gas Purchased. The $67 million increase was driven primarily by:

a $146 million increase from higher natural gas prices passed through to customers,

a $60 million increase caused by Canadian dollar exchange effects, and

a $10 million increase as a result of growth in the number of customers, partially offset by

a $157 million decrease primarily resulting from lower gas usage due to unseasonably warmer weather.

Operating, Maintenance and Other. The $26 million increase was driven primarily by:

a $19 million increase caused by Canadian dollar exchange effects, and

a $7 million increase primarily related to higher labor and benefit costs.

Depreciation and Amortization. The $15 million increase was driven primarily by:

a $6 million increase resulting from expansion projects placed into service, and

a $9 million increase caused by Canadian dollar exchange effects.

EBIT. The $12 million decrease was primarily due to lower gas distribution margins associated with warmer weather and the resulting lower customer usage as compared with 2005, and higher operating costs. These decreases were partially offset by the Canadian dollar exchange effects.

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Matters Affecting Future Distribution Results

Distribution plans to continue earnings growth through capital efficient market pull expansion projects of transportation and storage capacity to support the projected demand growth in the Ontario market. The projected natural gas demand in Ontario benefits the continued retail distribution growth as well. Distribution s earnings are affected significantly by weather during the winter heating season. In addition, earnings over the last several years have benefited from the strengthening Canadian dollar and will be affected by future changes in the U.S./Canadian dollar exchange rates. As with all of Spectra Energy s regulated entities, regulatory changes may affect future earnings.

Effective January 2008, a multi-year incentive rate structure became effective for Union Gas that provides for a slight increase in overall rates as compared to 2007, and includes an allowance for annual inflation adjustments, productivity and the impact of declining average use per customer.

Western Canada Transmission & Processing

	2007	2006	Increase (Decrease)	2005	Increase (Decrease)
	(in millions, except where noted)				
Operating revenues	$ 1,304	$ 1,204	$ 100	$ 874	$ 330
Operating expenses					
Natural gas and petroleum products purchased	362	349	13	216	133
Operating, maintenance and other	421	392	29	306	86
Depreciation and amortization	141	133	8	120	13
Gains on sales of other assets and other, net				6	(6)
Operating income	380	330	50	238	92
Other income and expenses, net		25	(25)	6	19
Minority interest expense	14	10	4	1	9
EBIT	$ 366	$ 345	$ 21	$ 243	$ 102
Pipeline throughput, Tbtu	596	594	2	636	(42)
Volumes processed, Tbtu	709	730	(21)	607	123
Empress inlet volumes, Tbtu	722	811	(89)	354	457

2007 Compared to 2006

Operating Revenues. The $100 million increase was driven by:

an $81 million increase caused by the strengthening Canadian dollar in 2007, and

a $33 million increase due to higher NGL prices associated with the Empress operations, partially offset by lower NGL sales volumes, mainly as a result of a plant maintenance turnaround in 2007, partially offset by,

an $18 million decrease resulting from lower processing volumes in the Fort Nelson area of northeastern British Columbia.

Natural Gas and Petroleum Products Purchased. The $13 million increase included:

a $21 million increase caused by Canadian dollar exchange effects in 2007, and

a $10 million decrease from lower volumes of natural gas purchased for the Empress facility, mainly as a result of a plant maintenance turnaround in 2007.

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Operating, Maintenance and Other. The $29 million increase was driven by:

- a $25 million increase caused by Canadian dollar exchange effects in 2007, and
- an $8 million increase due to higher plant maintenance turnaround costs in 2007 (Empress and Pine River) compared to 2006 (Fort Nelson), partially offset by
- a $6 million decrease in plant fuel costs at the Empress facility, mainly as a result of a plant maintenance turnaround in 2007.

Depreciation and Amortization. The $8 million increase was driven primarily by Canadian dollar exchange effects in 2007.

Other Income and Expenses and Other, net. The 2006 amount included a $15 million gain resulting from the Income Fund s issuance of units for the purchase of Westcoast Gas Services Inc.

Minority Interest Expense. The $4 million increase was driven primarily by the decrease in the ownership of the operations of the Income Fund in the third quarter of 2006, from 58% to 46%, when additional trust units were sold by the Income Fund.

EBIT. The $21 million increase resulted from higher NGL prices and Canadian dollar exchange effects partially offset by lower natural gas processing volumes, and the 2006 gain resulting from the sale of Income Fund units.

2006 Compared to 2005

Operating Revenues. The $330 million increase was driven by:

- a $279 million increase in processing revenues, due primarily to the Empress System purchased in August 2005 and associated stronger commodity prices in 2006 compared to 2005, and
- a $47 million increase due to Canadian dollar exchange rates favorably impacting revenues as a result of the strengthening Canadian dollar.

Natural Gas Purchased. The $133 million increase was driven primarily by:

- a $131 million increase due to the Empress assets purchased in August 2005 and higher gas prices in 2006, and
- a $7 million increase caused by Canadian dollar exchange rate effects.

Operating, Maintenance and Other. The $86 million increase was driven primarily by:

- a $43 million increase due to the Empress assets purchased in August 2005,

a $25 million increase caused by Canadian dollar exchange rate effects, and

a $12 million increase related to higher labor and benefit costs and higher insurance premiums.

Depreciation and Amortization. The $13 million increase was driven primarily by:

a $9 million increase caused by Canadian dollar exchange rate effects, and

a $6 million increase due to Empress assets purchased in August 2005.

Other Income and Expenses, net. The $19 million increase was driven primarily by a pre-tax SAB No. 51 gain of $15 million related to the Income Fund s issuance of additional units.

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Minority Interest Expense. The $9 million increase resulted from the 2006 issuance of Trust Units in the Income Fund, which reduced Spectra Energy s ownership in those operations to approximately 46% as of December 31, 2006.

EBIT. The $102 million increase was primarily due to the increase in processing earnings (primarily Empress System), the gain resulting from the Income Fund s issuance of additional units and favorable Canadian dollar exchange effects from the strengthening Canadian dollar.

Matters Affecting Future Western Canada Transmission & Processing Results

Western Canada Transmission & Processing plans to continue earnings growth through capital efficient supply push projects, primarily associated with gathering and processing expansion to support drilling activity in northern British Columbia. Earnings will also continue to benefit through optimizing the performance of the existing system and through organizational efficiencies. Earnings can fluctuate from period-to-period as a result of the timing of processing plant turnarounds that reduce revenues while the plant is out of service and increase operating costs as a result of the turnaround maintenance work. Western Canada Transmission and Processing s 19 processing plants are generally scheduled for turnaround work every two to three years, with the work being staggered to prevent significant outages at any given time in a single geographic area. In addition, future earnings will be affected by the ability to renew service contracts and regulatory stability. Earnings from processing services will be affected by the ability to access additional natural gas reserves. In addition, the Empress NGL business will be affected by both gas flows and the effects of natural gas and NGL commodity prices.

During the period 2004 through 2006, Western Canada experienced historic levels of natural gas drilling activity. Beginning in late 2006, a reduction in Western Canadian drilling has been occurring when compared to the levels generally experienced during the previous three years. Overall, exploration and development activity in Western Canada Transmission & Processing s core areas has been relatively steady, with strong continued throughputs in the Pine River and McMahon areas, with the most significant decline being in the Fort Nelson region of Northeast British Columbia. In addition, although the actual effects will not be known for some time, the Alberta government s recently announced New Royalty Framework, proposed to be effective January 1, 2009, could affect certain of Westcoast s Alberta operations. The operations in British Columbia could be positively affected by this change in royalties if producers reduce drilling in Alberta and increase drilling in British Columbia. Management continues to believe that low-to-moderate growth in Western Canada is reasonable over the long-term.

Field Services

	2007	2006	Increase (Decrease)	2005	Increase (Decrease)
	(in millions, except where noted)				
Operating revenues	$	$	$	$ 5,530	$ (5,530)
Operating expenses		5	(5)	5,215	(5,210)
Gains on sales of other assets and other, net				577	(577)
Operating income		(5)	5	892	(897)
Equity in earnings of unconsolidated affiliates(a)	533	574	(41)	292	282
Other income and expenses, net				1,259	(1,259)
Minority interest expense				497	(497)
EBIT	$ 533	$ 569	$ (36)	$ 1,946	$ (1,377)
Natural gas gathered and processed/transported, TBtu/d(b)	6.8	6.8		6.8	
NGL production, MBbl/d(c)	363	361	2	353	8
Average natural gas price per MMBtu(d)	$ 6.86	$ 7.23	$ (0.37)	$ 8.59	$ (1.36)
Average NGL price per gallon(e)	$ 1.11	$ 0.94	$ 0.17	$ 0.85	$ 0.09

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(a) Includes Spectra Energy s 50% equity in earnings of DCP Midstream net income subsequent to the deconsolidation of DCP Midstream effective July 1, 2005. Results of DCP Midstream 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

2007 Compared to 2006

EBIT. Lower equity in earnings of $36 million were primarily the result of the following variances, each representing Spectra Energy s 50% ownership portion of the earnings drivers at DCP Midstream:

a $60 million decrease in marketing margins, including a $39 million loss on hedges related to commodity non-trading activity that were executed by DCP Partners,

a $59 million decrease in gathering and processing margins attributable to decreased natural gas and NGL volumes, primarily from the effects of severe weather, including downtime for repairs, as well as an increase in plant inefficiencies and contract renegotiations at less favorable terms,

a $56 million decrease resulting from higher operating costs of $24 million, administrative costs of $16 million and depreciation costs of $16 million primarily attributable to asset acquisitions, industry price pressures on materials, contract services and labor and higher repairs and maintenance costs, including $12 million in costs associated with DCP Midstream s initiative to create stand-alone corporate functions, separate from the two partners of DCP Midstream,

an $18 million decrease due to higher net interest expense resulting from the increased debt associated with acquisitions in 2007,

a $14 million decrease as a result of a gain on the sale of gathering assets during 2006, and

a $9 million decrease resulting from decreased physical volume related to natural gas asset based trading and marketing, partially offset by

a $156 million increase from commodity sensitive processing arrangements, due to increased commodity prices,

a $15 million increase attributable to lower minority interest expense as a result of lower earnings at DCP Midstream Partners, and

a $6 million increase as a result of lower income tax expense primarily due to a 2006 adjustment to establish deferred tax liabilities for the new Texas margin tax.

2006 Compared to 2005

In July 2005, Duke Energy caused a Spectra Energy subsidiary to complete the transfer of a 19.7% interest in DCP Midstream to ConocoPhillips, Spectra Energy s co-equity owner in DCP Midstream, which reduced Spectra Energy s ownership interest in DCP Midstream from 69.7% to 50% and resulted in Spectra Energy and ConocoPhillips becoming equal 50% owners in DCP Midstream. As a result of the DCP Midstream disposition transaction, Spectra Energy deconsolidated its investment in DCP Midstream and subsequently has accounted for DCP Midstream as an investment utilizing the equity method of accounting.

Operating Revenues. The $5,530 million decrease was due to the DCP Midstream disposition transaction and subsequent deconsolidation of DCP Midstream.

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Operating Expenses. The $5,210 million decrease was due to the DCP Midstream disposition transaction and subsequent deconsolidation of DCP Midstream. Operating expenses for 2005 were also affected by $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 $577 million decrease was due primarily to a pre-tax gain of $575 million on the DCP Midstream disposition transaction in the prior year.

Equity in Earnings of Unconsolidated Affiliates. The $282 million increase was due to Spectra Energy s 50% of equity in earnings of DCP Midstream s net income for the twelve months ended December 31, 2006 compared to equity in earnings of DCP Midstream s net income for the six months ended December 31, 2005. DCP Midstream earnings during the twelve months ended December 31, 2006 continued to be favorably affected by increased NGL and crude oil prices 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 $1,259 million decrease was due to the DCP Midstream disposition transaction and subsequent deconsolidation of DCP Midstream. In 2005, DCP Midstream 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 Spectra Energy had a pre-tax gain on the sale of its limited partner interest in TEPPCO LP of $97 million. TEPPCO GP and Spectra Energy s limited partner interest in TEPPCO LP were each sold to Enterprise GP Holdings LP, an unrelated third party.

Minority Interest Expense. The $497 million decrease was due to the DCP Midstream disposition transaction and subsequent deconsolidation of DCP Midstream. Minority interest expense for 2005 was due primarily to the gain on the sale of TEPPCO GP to Enterprise GP Holdings LP for $1.1 billion, as discussed above.

EBIT. The $1,377 million decrease resulted primarily from the gain on sale of TEPPCO GP and Spectra Energy s limited partner interest in TEPPCO LP in 2005 and gain on the DCP Midstream disposition transaction in 2005. These decreases were partially offset by increased NGL and crude oil prices in 2006 compared to the prior year.

Supplemental Data

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

	Twelve Months Ended December 31, 2007	Twelve Months Ended December 31, 2006	Six Months Ended December 31, 2005
		(in millions)	
Operating revenues	$ 13,154	$ 12,335	$ 7,463
Operating expenses	11,959	11,063	6,814
Operating income	1,195	1,272	649
Other income and expenses, net	44	5	1
Interest expense, net	154	119	62
Income tax expense	11	23	4
Net income	$ 1,074	$ 1,135	$ 584

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Matters Affecting Future Field Services Results

Field Services, through its 50% investment in DCP Midstream, has developed significant size and scope in natural gas gathering, processing and NGL marketing and plans to focus on operational excellence and organic growth. DCP Midstream s revenues and expenses are significantly dependent on prevailing commodity prices for NGLs and natural gas, and past and current trends in price changes of these commodities may not be indicative of future trends. DCP Midstream anticipates that current price levels will continue to stimulate drilling and help to offset declining raw natural gas supplies. Although the prevailing price of natural gas has less short-term significance to its operating results than the price of NGLs, in the long term, the growth and sustainability of DCP Midstream s business depends on natural gas prices being at levels sufficient to provide incentives and capital for producers to increase natural gas exploration and production. Future equity in earnings of DCP Midstream will continue to be sensitive to commodity prices that have historically been cyclical and volatile. There are many important factors that could cause actual results to differ materially from the expectations expressed, including but not limited to future commodity prices, drilling activity, inflation and the effects of severe weather. Management can provide no assurances regarding the effect of these factors.

Commercial Power

	2007	2006	Increase (Decrease)	2005	Increase (Decrease)
			(in millions)		
Operating revenues	$	$	$	$	$
Operating expenses					
Losses on sales of other assets and other, net				(70)	70
Operating income				(70)	70
Other income and expenses, net					
EBIT	$	$	$	$ (70)	$ 70

Commercial Power, which did not have any operations or net assets within Spectra Energy effective after December 31, 2005, consisted of a portion of the DENA operations, primarily merchant power plants and certain other power and gas contracts (collectively, the Southeast Plants). Spectra Energy sold the Southeast Plants in 2004 and the remaining contracts in 2005. The 2005 Losses on Sales of Other Assets and Other, Net represented the pre-tax charge related to the termination of structured power contracts in the Southwest region. Commercial Power is reported as a business segment in 2005 as a result of continuing involvement identified at the time of the sale.

Other

	2007	2006	Increase (Decrease)	2005	Increase (Decrease)
			(in millions)		
Operating revenues	$ 31	$ 29	$ 2	$ (1)	$ 30
Operating expenses	150	175	(25)	288	(113)
Gains on sales of other assets and other, net		2	(2)	4	(2)
Operating income	(119)	(144)	25	(285)	141
Other income and expenses, net	7	67	(60)	35	32
EBIT	$ (112)	$ (77)	$ (35)	$ (250)	$ 173

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2007 Compared to 2006

Operating Expenses. The $25 million decrease was primarily driven by:

- $25 million of lower operating expenses as a result of the reduced portfolio and activity of the U.S. captive insurance entity, and
- $19 million of costs allocated from Duke Energy associated with the Cinergy merger in 2006, partially offset by
- $11 of higher corporate costs related to higher employee incentives and benefits costs, and
- $8 million of higher gas spin-off separation costs in 2007 ($23 million) compared to 2006 ($15 million).

Other Income and Expenses, net. The $60 million decrease resulted from the management fees collected from certain Duke Energy operations in 2006 of $82 million, partially offset by the 2006 mark-to-market losses of $19 million for hedge positions associated with the earnings of the Field Services segment.

EBIT. The $35 million decrease was primarily due to management fees earned from a Duke Energy affiliate in 2006 partially offset by 2006 net hedge losses associated with the Field Services segment and lower 2007 net corporate costs.

2006 Compared to 2005

Operating Revenues. The $30 million increase was driven primarily by:

- a $130 million increase as a result of the prior year effect 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 DCP Midstream, effective July 1, 2005, partially offset by
- an $87 million decrease in captive insurance revenues due to the transfer of ownership in Bison to Duke Energy effective April 1, 2006, and
- a $21 million decrease due to a prior year mark-to-market gain related to DENA s hedge discontinuance in the Southeast.

Operating Expenses. The $113 million decrease was driven primarily by:

- a $133 million decrease in captive insurance expenses due primarily to the transfer of ownership in Bison to Duke Energy effective April 1, 2006, and prior year recognition of reserves for estimated property damage related to hurricanes and business interruption losses, partially offset by
- a $13 million increase primarily associated with Spectra Energy s allocated share of Duke Energy s costs to achieve the Cinergy merger in 2006.

Other Income and Expenses, net. The $32 million increase was driven primarily by a $45 million favorable variance resulting from the realized and unrealized mark-to-market effects 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 DCP Midstream, effective July 1, 2005. Other income and expenses, net includes $82 million in 2006 and $68 million in 2005 related to management fees charged to an unconsolidated affiliate.

EBIT. The $173 million increase was due primarily to the favorable variance related to realized and unrealized mark-to-market effects of certain discontinued cash flow hedges originally entered into to hedge Field Services commodity price risk and prior year recognition of reserves for estimated property damage related to

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hurricanes and business interruption, partially offset by the prior year mark-to-market gain related to DENA hedge discontinuance in the Southeast.

Matters Affecting Future Other Results

Future Other results will continue to include corporate and business services provided for the operations of Spectra Energy, and will also include operating costs and self-insured losses associated with Spectra Energy s captive insurance entities.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The application of accounting policies and estimates is an important process that continues to evolve as Spectra Energy s operations change and accounting guidance is issued. Spectra 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 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. Spectra Energy discusses its critical accounting policies and estimates and other significant accounting policies with the Audit Committee of Spectra Energy.

Regulatory Accounting

Spectra Energy accounts for certain of its regulated operations under the provisions of Statement of Accounting Standards (SFAS) No. 71, Accounting for the Effects of Certain Types of Regulation. As a result, Spectra Energy records assets and liabilities that result from the regulated ratemaking process that would not be recorded under generally accepted accounting principles (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 changes and recent rate orders to other regulated entities. 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, 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 and amortization of regulatory assets. Total regulatory assets were $889 million as of December 31, 2007 and $959 million as of December 31, 2006. Total regulatory liabilities were $568 million as of December 31, 2007 and $569 million as of December 31, 2006.

Impairment of Goodwill

Spectra Energy had goodwill balances of $3,948 million at December 31, 2007 and $3,507 million at December 31, 2006. Spectra Energy evaluates the impairment of goodwill under SFAS No. 142, Goodwill and Other Intangible Assets. The majority of Spectra Energy s goodwill relates to the acquisition of Westcoast Energy, Inc. (Westcoast) in March 2002, which owns the majority of Spectra Energy s Canadian operations. As of the acquisition date or upon a change in reporting units, Spectra Energy allocates goodwill to a reporting unit, which Spectra Energy defines as an operating segment or one level below an operating segment. As required by SFAS No. 142, Spectra 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

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rate and estimated future cash flows. In estimating cash flows, Spectra Energy incorporates expected growth rates, regulatory stability, the ability to renew contracts, and foreign currency exchange rates, as well as other factors that affect its revenue and expense forecasts.

The long-term growth rates and projected cash flows of the gathering and processing activities in Western Canada are sensitive to assumptions around the prospects for natural gas exploration and drilling in the areas of British Columbia and Alberta that are in close proximity to Spectra Energy s Western Canada assets (primarily in the western extent of the Western Canadian Sedimentary Basin). Although drilling slowed in 2006 and 2007 in certain of these areas (primarily in northeastern British Columbia), management believes that low-to-moderate growth in Spectra Energy s operations is reasonable over the long-term. If this growth and expansion does not materialize in periods after 2010, the BC Field Services reporting unit could experience a decline in overall unit value, which could affect the ability to support the goodwill allocated to this unit.

Revenue Recognition

Revenues from the transportation, storage, distribution and sales of natural gas, and from the sales of NGLs, 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.

Pension and Other Post-Retirement Benefits

The calculations of pension and other post-retirement expense and liabilities require the use of numerous assumptions. Changes in these assumptions can result in different reported expense and liability amounts, and future actual experience can differ from the assumptions. Spectra 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. In addition, medical and prescription drug cost trend rate assumptions are critical for other post-retirement benefits. Future changes in plan asset returns, assumed discount rates and various other factors related to the participants in Spectra Energy s pension and post-retirement plans will impact future pension expense and liabilities.

LIQUIDITY AND CAPITAL RESOURCES

Known Trends and Uncertainties

Spectra Energy will rely primarily upon cash flows from operations and additional financing transactions to fund its liquidity and capital requirements for 2008. As of December 31, 2007, Spectra Energy had negative working capital of approximately $1,043 million. This balance includes short-term debt of $715 million and current maturities of long-term debt of $338 million which are expected to be financed through additional long-term borrowings. Spectra Energy also has access to four revolving credit facilities, with total combined capacities of approximately $2.7 billion. These facilities will be used principally as a back-stop for commercial paper programs.

Cash flows from operations are subject to a number of factors, including, but not limited to, earnings sensitivities to weather, commodity prices, and the timing of associated regulatory cost recovery approval. See Part I, Item 1A. Risk Factors for further discussion.

As Spectra Energy executes on its strategic objectives around organic growth and expansion projects, expansion expenditures could average more than $1 billion per year over the next few years. However, the timing and extent of these expenditures are likely to vary significantly from year to year. Given the anticipated levels of

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capital and investment expenditures in 2008 and over the next few years, capital resources will include significant long-term borrowings, including estimated new borrowings of approximately $1.5 billion in 2008. However, as a result of expansion earnings contributions and ongoing strong earnings performance expected in the existing operations, Spectra Energy expects to maintain a capital structure and liquidity profile that continues to support an investment-grade credit rating.

Operating Cash Flows

Net cash provided by operating activities increased $773 million to $1,467 million in 2007 compared to 2006. This change was driven primarily by:

- a $600 million payment to Barclays in 2006 in connection with the sale of certain commodity, energy marketing and management contracts of DENA,
- approximately $400 million of net settlement cash outflows in 2006 related to remaining DENA contracts, and
- capital expenditures of $322 million in 2006 for residential real estate, partially offset by
- collateral of $540 million received by Spectra Energy in 2006 from Barclays, and
- net payments in 2007 of $82 million to resolve certain litigation matters associated with discontinued LNG operations.

Net cash provided by operating activities decreased $375 million to $694 million in 2006 compared to 2005. This change was driven primarily by:

- a $600 million payment to Barclays in 2006 in connection with the sale of certain commodity, energy marketing and management contracts of DENA, and
- approximately $400 million of net settlement cash outflows in 2006 related to remaining DENA contracts, partially offset by
- collateral of $540 million received by Spectra Energy in 2006 from Barclays.

Investing Cash Flows

Net cash flows used in investing activities totaled $1,544 million in 2007 compared to net cash flows provided by investing activities of $1,569 million in 2006. This $3,113 million decrease was driven primarily by:

- approximately $2.0 billion in proceeds received in 2006 from the sales of equity investments and other assets, primarily the sale of DENA assets and an interest in Crescent,

a $672 million increase in capital and investment expenditures in 2007 associated with the U.S. Transmission, Distribution and Western Canada Transmission & Processing segments,

net purchases of available-for-sale securities of $145 million in 2007 compared to net sales of $485 million in 2006, and

proceeds totaling $254 million in the 2006 period from real estate sales activity of operations transferred to Duke Energy in December 2006, partially offset by

capital expenditures of $695 million in 2006 associated with the operations that were transferred to Duke Energy.

Net cash flows provided by investing activities totaled $1,569 million in 2006 compared to $1,241 million in 2005. This $328 million increase was primarily driven by:

net sales of available-for-sale securities of $485 million in 2006 compared to net purchases of $212 million in 2005, and

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a decrease in cash used for acquisitions of approximately $200 million, as a result of the approximately $230 million 2005 acquisition of the Empress System at Western Canada Transmission & Processing, partially offset by

a decrease in proceeds received from asset sales in 2006 as compared to 2005. Asset sales activity in 2006 of approximately $2.0 billion primarily involved the disposal of the DENA operations outside of the Midwestern United States, 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 DCP Midstream disposition transaction,

a decrease of $118 million in proceeds from real estate sales activity of operations transferred to Duke Energy in December 2006, and

$152 million of distributions from equity investees that were considered returns of equity in 2006 (primarily DCP Midstream), as compared to $383 million in 2005.

Capital and Investment Expenditures by Business Segment

Capital and investment expenditures are detailed by business segment in the following table. Capital and investment expenditures presented below include expenditures from both continuing and discontinued operations.

	2007	2006	2005
		(in millions)	
Capital and Investment Expenditures			
U.S. Transmission	$ 898	$ 343	$ 388
Distribution	369	315	172
Western Canada Transmission & Processing	195	132	370
Field Services(a)			86
International Energy		58	23
Crescent(b)		185	244
Other	39	130	31
Total consolidated	$ 1,501	$ 1,163	$ 1,314

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

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

Capital and investment expenditures for 2007 totaled $1,501 million and included $1,003 million for expansion projects and $498 million for maintenance and other projects. Spectra Energy projects 2008 capital and investment expenditures of approximately $2.4 billion, consisting of approximately $1.7 billion for U.S. Transmission, $0.4 billion for Distribution and $0.3 billion for Western Canada Transmission & Processing. Total projected 2008 capital and investment expenditures include approximately $1.9 billion of expansion capital expenditures and $0.5 billion for maintenance and upgrades of existing plants, pipelines and infrastructure to serve growth.

Expansion capital expenditures in 2007 included several key projects placed into service in 2007, such as Algonquin s Northeast Gateway deepwater connection with an LNG port and Union Gas Dawn-Trafalgar Phase II pipeline expansion that provides capacity primarily for ex-franchise customers under long-term contracts. Additionally, 2007 expansion capital included work on several other multi-year projects,

including the Maritimes & Northeast, Texas Eastern and Southeast Supply Header projects described further below.

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Significant 2008 expansion projects are expected to include:

Gulfstream Phase III, expected to begin service in August 2008, includes approximately 35 miles of 30-inch pipeline. Phase IV includes about 18 miles of 20-inch pipe and increased compression and is expected to be in service in September 2008. Both projects will be serving the growing electricity needs of peninsular Florida.

Egan Increase storage working capacity by 8 Bcf and expansion of the Texas Eastern interconnect for additional injection and withdrawal capabilities. This capacity is expected to be in service in August 2008 and will enable Egan to capture opportunities around new LNG supply along the Gulf Coast.

Maritimes & Northeast Phase IV Expansion of capacity on the U.S. portion of the Maritimes & Northeast pipeline to move additional gas coming online in November 2008 from the Canaport LNG terminal in New Brunswick, Nova Scotia for deliveries into the Northeast United States.

Texas Eastern Transmission Time II Involves new pipeline looping and compression to deliver an additional 150 million cubic feet per day (MMcf/d) from Lebanon, Ohio to New Jersey. Phase I of this project was placed into service December 1, 2007 and provides capacity from western Pennsylvania. Phase II will extend the capacity back to Lebanon, Ohio and is expected to be placed into service by November 2008.

Southeast Supply Header (SESH) This joint venture with CenterPoint Energy, Inc. involves the construction of approximately 270 miles of new pipeline from the Perryville Hub in northern Louisiana to connect near Mobile, Alabama with the Gulfstream Natural Gas System. It will connect the natural gas supply basins of east Texas and north Louisiana to southeast markets and will interconnect with numerous interstate pipelines. This new pipeline is expected to be in-service in the summer of 2008.

Dawn-Trafalgar Phase III of this Union Gas pipeline expansion consists of increased compression, expected to come on-line in November 2008, to create incremental transmission capacity for key power markets in Ontario and to support government initiatives to meet electric shortfalls with gas fired power plants.

Dawn Storage Deliverability Provides for approximately 500 MMcf/d of incremental storage deliverability, expected to be in service in November 2008. Compression, wells and pipeline make up the new facilities.

Ramapo An Algonquin capacity expansion, including 82,000 horsepower of new compression, to serve markets in the Northeast. Expected to be in-service in November 2008.

Financing Cash Flows and Liquidity

Spectra Energy s consolidated capital structure as of December 31, 2007, including short-term debt, was 55% debt, 40% stockholders equity and 5% minority interests.

Net cash used in financing activities totaled $191 million in 2007 compared to $2,454 million in 2006. This change was driven primarily by:

approximately $2.4 billion of distributions to Duke Energy in 2006 primarily due to the Crescent joint venture transaction,

$230 million of net proceeds received in 2007 from Spectra Partners, as discussed further below, and

$366 million of commercial paper issued in 2007 compared to $261 million during 2006, partially offset by

a $335 million decrease in 2007 in proceeds from issuances of long-term debt, net of redemptions, and

dividends paid on common stock of $558 million in the 2007 period as compared with $89 million of advances made to Duke Energy in 2006.

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Net cash used in financing activities was $2,454 million in 2006 compared to $2,341 million in 2005. This change was driven primarily by:

- a $221 million increase in distributions to parent, net of capital contributions, in 2006, due primarily to the 2006 proceeds from the Crescent JV transaction, and
- the transfer of $118 million of cash held at Bison to Duke Energy during 2006, partially offset by
- a $680 million increase in 2006 in net proceeds from the net issuances of long-term debt, notes payable and commercial paper, and
- $89 million of advances made to Duke Energy in 2006 as compared with $242 million in 2005.

Significant Financing Activities 2007

In July 2007, Spectra Energy completed the IPO of Spectra Partners and received total proceeds of approximately $345 million as a result of the transaction, including the debt issued as discussed below. Net cash of approximately $230 million was received by Spectra Partners upon closing of the IPO. Approximately $26 million of these proceeds was distributed to Spectra Energy, $194 million was used by Spectra Partners to purchase qualifying investment grade securities, and $10 million was retained by Spectra Partners to meet working capital requirements. Spectra Partners borrowed $194 million in term debt using the investment grade securities as collateral and borrowed an additional $125 million of revolving debt. Proceeds from these borrowings, totaling $319 million, were distributed to Spectra Energy. In conjunction with the public offering associated with Spectra Partners discussed further in Item 8. Financial Statements and Supplemental Data, Note 2 of Notes to Consolidated Financial Statements, Spectra Partners entered into a five-year $500 million facility that includes both term and revolving borrowing capacity. Obligations under the revolving portion of its credit facility are unsecured and the term borrowings are secured by qualifying investment grade securities in an amount equal to or greater than the outstanding principal amount of the loan.

In July 2007, Union Gas replaced the existing $400 million Canadian 364-day credit facility with a $500 million Canadian five-year credit facility.

In May 2007, Spectra Capital entered into a $1.5 billion credit facility that replaced two existing facilities that totaled $950 million.

Significant Financing Activities 2006

Union Gas issued 125 million Canadian dollars of 4.85% fixed-rate debentures ($108 million U.S. dollar equivalents as of the closing date) due in 2022, and 165 million Canadian dollars of 5.46% fixed-rate debentures ($148 million in U.S. dollar equivalents as of the issuance date) due in 2036.

In September 2006, prior to the completion of the partial sale of Crescent as discussed in Note 9 of Notes to Consolidated Financial Statements, 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 financing activity on the Consolidated Statements of Cash Flows. As a result of Spectra Energy s deconsolidation of Crescent effective September 7, 2006, Crescent s outstanding debt balance of $1,298 million was removed from Spectra Energy s Consolidated Balance Sheets.

The Income Fund, a Canadian income trust fund, sold approximately 9 million previously unissued Trust Units for proceeds of $94 million, net of commissions and other expenses of issuance. The sale of these Trust Units reduced Spectra 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, Spectra Energy recognized a $15 million pre-tax gain on the sale of subsidiary stock. The proceeds from the offering plus the draw down of 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. from Spectra Energy.

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During 2006, Spectra Energy advanced $89 million to Duke Energy and forgave advances to Duke Energy of $602 million. Additionally during 2006, Spectra Energy distributed $2,361 million to Duke Energy to provide funding support for Duke Energy s dividend payments and share repurchase plan. The distribution was principally obtained from the proceeds received on Spectra Energy s sale of 50% of Crescent.

Significant Financing Activities 2005

In December 2005, the Income Fund was created which sold approximately 40% ownership in the Canadian Midstream operations for proceeds, net of underwriting discount, of $110 million. Also in 2005, Union Gas issued 200 million Canadian dollars of 4.64% fixed-rate debentures ($171 million in U.S. dollar equivalents as of the issuance date) due in 2016.

Spectra Energy received a $269 million capital contribution from Duke Energy, which Spectra Energy classified as an addition to Member s Equity. In addition, Spectra Energy distributed $2.1 billion to Duke Energy to principally provide for funding for the execution of Duke Energy s accelerated share repurchase transaction and to provide funding support for Duke Energy s dividend. The distribution was primarily funded by Spectra Energy s portion of the cash proceeds realized from the sale by DCP Midstream of TEPPCO GP and Spectra Energy s sale of its limited partner interest in TEPPCO LP.

Available Credit Facilities and Restrictive Debt Covenants

			Outstanding at December 31, 2007			
	Expiration Date	Credit Facilities Capacity	Commercial Paper	Term Loan	Revolving Credit	Letters of Credit	Total
				(in millions)			
Spectra Energy Capital, LLC	2012	$ 1,500(a)	$ 478	$	$	$ 16	$ 494
Westcoast Energy, Inc.	2011	200(b)					
Union Gas Limited	2012	501(c)	237				237
Spectra Energy Partners, LP	2012	500(d)		153	97		250
Total		$ 2,701	$ 715	$ 153	$ 97	$ 16	$ 981

(a) Credit facility contains a covenant requiring the debt-to-total capitalization ratio to not exceed 65%.
(b) 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%.
(c) Credit facility is denominated in Canadian dollars totaling 500 million Canadian dollars and contains a covenant that requires the debt-to-total capitalization ratio to not exceed 75%. The facility also contains a provision which requires Union Gas to repay all borrowings under the facility for a period of two days during the second quarter of each year.
(d) Contains a covenant requiring the borrower to collateralize the term loan with qualifying investment-grade securities in an amount equal to or greater than the outstanding principal amount of the loan. The terms of the credit facility allow for liquidation of collateral to fund capital expenditures or certain acquisitions provided that an equal amount of term loan is converted to a revolving loan.

Spectra 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, 2007, Spectra 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.

Pursuant to certain debt agreements of Maritimes & Northeast Pipeline Limited Partnership (M&N LP) and Maritimes & Northeast Pipeline, L.L.C. (M&N LLC) (both approximately 78% owned by Spectra Energy), of

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which $501 million of notes and $286 million of bank loans were outstanding at December 31, 2007, a deliverability report on the status of natural gas reserves was provided to the lender s collateral agent and trustee in late 2007. This report indicated that the deliverability of the natural gas reserves (excluding any consideration for LNG effects) specified in the debt agreements had begun to decline below the required throughput level. Accordingly, pursuant to the terms of the debt agreements, all cash available for distribution to equity holders from the M&N LP operations will be used prospectively to repay the bank loan of M&N LP and to escrow funds for the notes of M&N LP, and all cash available for distribution to equity holders from the M&N LLC operations will be used to escrow funds for the bonds of M&N LLC. Management expects this debt funding will not significantly affect Spectra Energy s overall liquidity or capital plans.

Credit Ratings Summary as of February 18, 2008

	Standard and Poor s	Moody s Investor Service	Dominion Bond Rating Service
Spectra Energy Capital, LLC(a)	BBB	Baa1	Not applicable
Texas Eastern Transmission, LP(a)	BBB+	A3	Not applicable
Westcoast Energy, Inc.(a)	BBB+	Not applicable	A(low)
Union Gas(a)	BBB+	Not applicable	A
Maritimes & Northeast Pipeline, LLC(b)	A-	A2	A
Maritimes & Northeast Pipeline, LP(b)	A	A2	A

(a) Represents senior unsecured credit rating
(b) Represents senior secured 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 the current balance sheets. These credit ratings could be negatively affected if as a result of market conditions or other factors, they are unable to maintain the current balance sheet strength, or if earnings and cash flow outlook materially deteriorates.

Dividends. Spectra Energy currently anticipates a dividend payout ratio of approximately 60% of estimated annual net income per share of common stock. Spectra Energy expects to continue its policy of paying regular cash dividends. The declaration and payment of dividends are subject to the sole discretion of Spectra Energy s Board of Directors and will depend upon many factors, including the financial condition, earnings and capital requirements of operating subsidiaries, covenants associated with certain debt obligations, legal requirements, regulatory constraints and other factors deemed relevant by the Board of Directors. On January 4, 2008, the Board of Directors increased the first quarter dividend to $0.23 per common share which will be paid on March 17, 2008. This dividend represents a 4.6% increase over the fourth quarter 2007 dividend.

Other Financing Matters. Spectra Energy and Spectra Capital have an automatic shelf registration statement on file with the SEC to register the issuance of an unspecified amount of various equity securities by Spectra Energy and various debt securities by Spectra Capital. In addition, as of December 31, 2007, subsidiaries of Spectra Energy had 810 million Canadian dollars (approximately U.S. $811 million) available under shelf registrations for issuances in the Canadian market. Of the 810 million Canadian dollars available under these shelf registrations, 500 million expires in May 2008 and 310 million expires in August 2008.

Off-Balance Sheet Arrangements

Spectra 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 guarantees, stand-by letters of credit, debt guarantees, surety bonds and indemnifications. See Item 8. Financial Statements and Supplementary Data, Note 19 of Notes to Consolidated Financial Statements for further discussion of guarantee arrangements.

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Most of the guarantee arrangements entered into by Spectra 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 Spectra Energy 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 Spectra Energy s operations. As such, if Spectra Energy discontinued issuing these guarantee arrangements, there would not be a material impact to the consolidated results of operations, financial position or cash flows.

In connection with the spin-off of Spectra Energy to Duke Energy shareholders, certain guarantees that were previously issued by Spectra Energy were assigned to, or replaced by, Duke Energy in 2006. For any remaining guarantees of other Duke Energy obligations, Duke Energy has indemnified Spectra Energy against any losses incurred under these guarantee arrangements.

Spectra Energy does not have any other material off-balance sheet financing entities or structures, except for normal operating lease arrangements, guarantee arrangements and financings entered into by equity investment pipeline and field services operations. For additional information on these commitments, see Item 8. Financial Statements and Supplementary data, Notes 18 and 19 of Notes to Consolidated Financial Statements.

Contractual Obligations

Spectra 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 Spectra 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. It is expected that the majority of current liabilities on the Consolidated Balance Sheets will be paid in cash in 2008.

Contractual Obligations as of December 31, 2007

	Payments Due By Period				
	Total	2008	2009 & 2010	2011 & 2012	2013 & Beyond
			(in millions)		
Long-term debt(a)	$ 14,285	$ 932	$ 2,795	$ 1,950	$ 8,608
Capital leases(a)	3	2	1		
Operating leases(b)	231	53	74	50	54
Purchase Obligations:(c)					
Firm capacity payments(d)	1,199	234	230	196	539
Energy commodity contracts(e)	751	660	30	31	30
Other purchase obligations(f)	340	308	30	2	
Other long-term liabilities on the Consolidated Balance Sheets(g)	56	56			
Total contractual cash obligations	$ 16,865	$ 2,245	$ 3,160	$ 2,229	$ 9,231

(a) See Note 16 of Notes to Consolidated Financial Statements. Amounts include scheduled interest payments over the life of debt or capital lease.
(b) See Note 18 of Notes to Consolidated Financial Statements.
(c) Purchase obligations reflected in the Consolidated Balance Sheets have been excluded from the above table.
(d) Includes firm capacity payments that provide Spectra Energy with uninterrupted firm access to natural gas transportation and storage.

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(e) Includes contractual obligations to purchase physical quantities of NGLs and natural gas. Amounts include certain hedges per SFAS No. 133, Accounting for Derivative Financial Instruments and Hedging Activities. For contracts where the price paid is based on an index, the amount is based on forward market prices at December 31, 2007.

(f) Includes contracts for software and consulting or advisory services. Amounts also include contractual obligations for engineering, procurement and construction costs for pipeline projects. Amounts exclude certain open purchase orders for services that are provided on demand, where the timing of the purchase can not be determined.

(g) Includes estimated 2008 retirement plan contributions and estimated 2008 payments related to FIN 48 liabilities, including interest (see Notes 8 and 22 of Notes to Consolidated Financial Statements). Spectra Energy is unable to reasonably estimate the timing of FIN 48 liability and interest payments in years beyond 2008 due to uncertainties in the timing of cash settlements with taxing authorities. Excludes cash obligations for asset retirement activities (see Note 15). The amount of cash flows to be paid to settle the asset retirement obligations is not known with certainty as Spectra Energy may use internal resources or external resources to perform retirement activities. Amounts also exclude reserves for litigation, environmental remediation and self-insurance claims (see Note 18), annual insurance premiums that are necessary to operate the business (see Note 18) and regulatory liabilities (see Note 5) because Spectra Energy is uncertain as to the amount and/or timing of when cash payments will be required. Also, amounts exclude 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.

Quantitative and Qualitative Disclosures About Market Risk

Spectra 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. The Chief Financial Officer of Spectra Energy is responsible for the overall governance of managing credit risk and commodity price risk, including monitoring exposure limits.

Commodity Price Risk

Spectra Energy is exposed to the effect of market fluctuations in the prices of NGLs and natural gas as a result of its investment in DCP Midstream, ownership of the Empress assets in Western Canada and processing plants associated with the U.S. pipeline assets. Price risk represents the potential risk of loss from adverse changes in the market price of these energy commodities. Spectra 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.

Spectra Energy employs established policies and procedures to manage its risks associated with these market fluctuations, which may include the use of forward physical transactions as well as commodity derivatives, primarily within DCP Midstream, such as swaps and options. 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. In the event the hedge is not effective, derivative gains and losses affect consolidated earnings. Several factors influence the effectiveness of a hedge contract, including the use of contracts with different commodities or unmatched terms and counterparty credit risk. When hedge accounting is used, hedge effectiveness is monitored regularly and measured each month.

Spectra Energy is primarily exposed to market price fluctuations of NGL prices in the Field Services segment and to frac-spreads in the Empress operations in Canada. Since NGL prices historically track crude oil prices, Spectra Energy discloses its NGL price sensitivities in terms of crude oil price changes. Based on a

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sensitivity analysis as of December 31, 2007 and 2006, at Spectra Energy s forecasted NGL-to-oil price relationships, a $10 per barrel move in oil prices would affect Spectra Energy s annual pre-tax earnings by approximately $135 million in 2008 ($120 million from Field Services and $15 million from U.S. Transmission) and approximately $170 million in 2007 ($150 million from Field Services and $20 million from U.S. Transmission). With respect to the frac-spread risk related to Empress processing and NGL marketing activities in Western Canada, as of December 31, 2007 and 2006, a $0.50 change in the difference between the Btu-equivalent price of propane (used as a proxy for Empress NGL production) and the price of natural gas in Alberta, Canada would affect Spectra Energy s pre-tax earnings by approximately $16 million on an annual basis in 2008 and approximately $13 million in 2007. These hypothetical calculations consider estimated production levels, but do not consider other potential effects that might result from such changes in commodity prices. The actual effect of commodity price changes of Spectra Energy s earnings could be significantly different than these estimates.

See also Item 8. Financial Statements and Supplementary Data, Notes 1 and 20 of Notes to Consolidated Financial Statements.

Credit Risk

Credit risk represents the loss that Spectra Energy would incur if a counterparty fails to perform under its contractual obligations. Spectra Energy s principal customers for natural gas transportation, storage, and gathering and processing services are industrial end-users, marketers, exploration and production companies, local distribution companies and utilities located throughout the U.S. and Canada. Spectra Energy has concentrations of receivables from these industry sectors. These concentrations of customers may affect Spectra Energy s overall credit risk in that risk factors can negatively affect the credit quality of an entire sector. Credit risk associated with gas distribution services are primarily affected by general economic conditions in the service territory.

Where exposed to credit risk, Spectra 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. Spectra Energy also obtains cash or letters of credit from customers to provide credit support, where appropriate, based on its financial analysis of the customer and the regulatory or contractual terms and conditions applicable to each transaction. Approximately 85% of Spectra Energy s credit exposures for transportation, storage, and gathering and processing services are with customers who have an investment-grade rating or equivalent based on an evaluation by Spectra Energy.

Spectra Energy manages cash and restricted cash positions to maximize value while assuring appropriate amounts of cash are available, as required. Spectra Energy invests its available cash in high-quality money market securities. Such money market securities are designed for safety of principal and liquidity, and accordingly, do not include equity-based securities. Spectra Energy has discontinued investing in both asset-backed commercial paper and auction-rate securities. One of Spectra Energy s Canadian operating companies had a $17 million net investment in asset-backed commercial paper outstanding in Canada as of December 31, 2007 and is participating in a plan to restructure this paper. The restructuring agreement proposed as a part of this plan is currently being supported by many large Canadian financial institutions as well as several international banks. In addition, Spectra Energy had a $44 million investment in auction-rate securities outstanding as of December 31, 2007 that was sold by January 4, 2008.

Spectra Energy had no net exposure to any one customer that represented greater than 10% of the gross fair value of trade accounts receivable at December 31, 2007.

Based on Spectra Energy s policies for managing credit risk, its exposures and its credit and other reserves, Spectra 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.

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Interest Rate Risk

Spectra Energy is exposed to risk resulting from changes in interest rates as a result of its issuance of variable and fixed rate debt and investments in short and long-term securities. Spectra Energy manages 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. Spectra 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 also Notes 1, 16, and 20 of Notes to Consolidated Financial Statements.

Based on a sensitivity analysis as of December 31, 2007, it was estimated that if market interest rates average 1% higher (lower) in 2008 than in 2007, interest expense, net of offsetting impacts in interest income, would increase (decrease) by $13 million. Comparatively, based on a sensitivity analysis as of December 31, 2006, had interest rates averaged 1% higher (lower) in 2007 than in 2006, it was estimated that interest expense, net of offsetting interest income, would have been approximately $8 million. These amounts were estimated by considering the effect of the hypothetical interest rates on variable-rate securities outstanding, adjusted for interest rate hedges, investments, and cash and cash equivalents outstanding as of December 31, 2007 and 2006. 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 Spectra Energy s financial structure.

Equity Price Risk

Spectra Energy s costs of providing non-contributory defined benefit retirement and postretirement benefit plans are dependent upon, among other things, rates of return on plan assets. These plan assets expose Spectra Energy to price fluctuations in equity markets. In addition, Spectra s captive insurance companies maintain various investments to fund certain business risks and losses. Those investments may, from time to time, include investments in equity securities.

Foreign Currency Risk

Spectra Energy is exposed to foreign currency risk from investments and operations in Canada. To mitigate risks associated with foreign currency fluctuations, investments are naturally hedged through debt denominated or issued in the foreign currency. Spectra Energy may also use foreign currency derivatives from time to time to manage its risk related to foreign currency fluctuations. To monitor its currency exchange rate risks, Spectra Energy uses sensitivity analysis, which measures the effect of devaluation of the Canadian dollar.

A 10% devaluation in the Canadian dollar exchange rate as of December 31, 2007 in Spectra Energy s currency exposure would result in an estimated net loss on the translation of local currency earnings of approximately $31 million to Spectra Energy s Consolidated Statements of Operations in 2008. In addition, the Consolidated Balance Sheet would be negatively impacted by $511 million currency translation through the cumulative translation adjustment in Accumulated Other Comprehensive Income (AOCI) as of December 31, 2007 as a result of a 10% devaluation in the currency exchange rate.

OTHER ISSUES

Global Climate Change. Spectra Energy s assets and operations in the U.S. and Canada may become subject to direct and indirect effects of possible future global climate change regulatory actions.

The United States is not a signatory to the United Nations-sponsored Kyoto Protocol, which prescribes specific targets to reduce greenhouse gas (GHG) emissions for developed countries for the 2008-2012 period, and the federal government has not adopted a mandatory GHG emissions reduction requirement. While several bills have been introduced in the U.S. Congress that would impose GHG emissions constraints, final legislation has yet to advance.

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While Canada is a signatory to the United Nations-sponsored Kyoto Protocol, the federal government has confirmed that it will not achieve the targets within the timeframes specified. Instead, the federal government is expected to introduce in 2008 a regulatory framework mandating GHG reductions from large final emitters. The framework is expected to require GHG emissions intensity reductions of 18% beginning in 2010, with further reductions of 2% per year thereafter.

A number of states in the U.S., primarily in the Northeast and Western U.S., are either in the process of establishing or considering state or regional programs that would mandate future reductions in greenhouse gas emissions. The final details and implementation schedules of such future state or regional programs, and whether they might directly affect the natural gas sector, are uncertain. In Canada, the province of British Columbia has introduced legislation establishing targets for the purpose of reducing GHG emissions to at least 33% less than 2007 levels by 2020 and to at least 80% less than 2007 levels by 2050. Specific emissions targets in British Columbia for 2012 and 2016 are expected to be established in 2008. In addition, in its February 2008 budget, the British Columbia government proposed a carbon tax that will apply, effective July 1, 2008, to the purchase or use of fossil fuels including natural gas consumed to process raw natural gas and in the operation of pipelines. Spectra Energy is currently assessing the potential impacts of this budget proposal. In 2007, the Province of Alberta adopted legislation which require existing large emitters (facilities releasing 100,000 tons or more of GHG emissions annually) to reduce their annual emissions intensity by 12% beginning July 1, 2007. The effect of this Alberta legislation did not materially affect consolidated results of operations, financial position or cash flows. The Alberta government is currently considering the next phase of development of its climate change action plan and additional regulations are anticipated. Legislation, regulations and programs mandating the reduction of GHG emissions in other provinces of Canada in which Spectra Energy has operations are still under development.

The key details of future GHG restrictions and related measures such as the proposed carbon tax are highly uncertain, and as such, the likely future affects on Spectra Energy are highly uncertain. Due to the speculative outlook regarding any U.S. federal and state policies and the uncertainty of the Canadian federal and provincial policies, Spectra Energy cannot estimate the potential effect of greenhouse gas policies on its future consolidated results of operations, financial position or cash flows. Spectra Energy will monitor the development of greenhouse gas regulatory policies in both countries as well as the states and provinces in which it operates in the U.S. and Canada if policies become sufficiently certain to support a meaningful assessment.

For additional information on other issues related to Spectra Energy, see Item 8. Financial Statements and Supplementary Data, Notes 5 and 18 of Notes to Consolidated Financial Statements.

New Accounting Pronouncements

The following new accounting pronouncements have been issued, but have not yet been adopted as of December 31, 2007:

SFAS No. 157, Fair Value Measurements. 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 Spectra Energy s current practice for measuring and disclosing fair values under other accounting pronouncements that require or permit fair value measurements. For Spectra Energy, SFAS No. 157 is effective as of January 1, 2008 and must be applied prospectively except in certain cases. The adoption of SFAS No. 157 is not expected to materially affect Spectra Energy s consolidated results of operations, financial position or cash flows.

SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities. In February 2007, the FASB issued SFAS No. 159, which permits entities to choose to measure certain financial instruments at fair

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value. For Spectra Energy, SFAS No. 159 is effective as of January 1, 2008. Spectra Energy has determined it will not elect fair value measurements for financial assets and financial liabilities included in the scope of SFAS No. 159.

SFAS No. 141R, Business Combinations. In December 2007, the FASB issued SFAS No. 141R which replaces SFAS No. 141, Business Combinations. SFAS No. 141R requires the acquiring entity in a business combination to recognize all (and only) the assets acquired and liabilities assumed in the transaction, establishes the acquisition-date fair value as the measurement objective for all assets acquired and liabilities assumed, and requires the acquirer to disclose to investors and other users all of the information they need to evaluate and understand the nature and financial effect of the business combination. SFAS 141R applies prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008 and cannot be early adopted.

SFAS No. 160, Noncontrolling Interest in Consolidated Financial Statements. In December 2007, the FASB issued SFAS No. 160 which requires all entities to report noncontrolling (minority) interests in subsidiaries as equity in the consolidated financial statements. SFAS No. 160 eliminates the diversity that currently exists in accounting for transactions between an entity and noncontrolling interests by requiring they be treated as equity transactions. SFAS No. 160 is effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008 and early adoption is prohibited. Spectra Energy is currently evaluating the impact of adopting SFAS No. 160, and cannot currently estimate the effect it will have on its consolidated results of operations, financial position or cash flows.

EITF 06-11, Accounting for Income Tax Benefits of Dividends on Share-Based Payment Awards. In June 2007, the FASB Emerging Issues Task Force (EITF) reached a consensus that a realized income tax benefit from dividends or dividend equivalents that are charged to retained earnings and are paid to employees for equity classified nonvested equity shares, nonvested equity share units, and outstanding equity share options should be recognized as an increase to additional paid-in capital. The amount recognized in additional paid-in capital for the realized income tax benefit from dividends on those awards should be included in the pool of excess tax benefits available to absorb tax deficiencies on share-based payment awards. EITF 06-11 will be applied prospectively to the income tax benefits that result from dividends on equity-classified employee share-based payment awards that are declared after December 31, 2007. The effect of adopting EITF 06-11 is not expected to be material to Spectra Energy s consolidated results of operations, financial position or cash flows.

EITF 07-01, Accounting for Collaborative Arrangements. In December 2007, the FASB ratified a consensus reached by the EITF to define collaborative arrangements and to establish reporting requirements for transactions between participants in a collaborative arrangement and between participants in the arrangement and third parties. A collaborative arrangement is a contractual arrangement that involves a joint operating activity. These arrangements involve two (or more) parties who are both (a) active participants in the activity and (b) exposed to significant risks and rewards dependent on the commercial success of the activity. EITF 07-01 is effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years. An entity should report the effects of applying EITF 07-01 as a change in accounting principle through retrospective application to all prior periods presented for all arrangements existing as of the effective date. Spectra Energy is currently evaluating the effect of adopting EITF 07-01, but does not believe it will have a material effect on its consolidated results of operations, financial position or cash flows.

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

See Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Quantitative and Qualitative Disclosures About Market Risk for discussion.

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Item 8. Financial Statements and Supplementary Data.

Management s Annual Report on Internal Control over Financial Reporting

Spectra 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). Spectra Energy s 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.

Spectra Energy s management, including its Chief Executive Officer and Chief Financial Officer, has conducted an evaluation of the effectiveness of its internal control over financial reporting as of December 31, 2007 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 Spectra Energy s internal control over financial reporting was effective as of December 31, 2007.

Spectra Energy s independent registered public accounting firm has audited and issued a report on the effectiveness of Spectra Energy s internal control over financial reporting, which is included in their Report of Independent Registered Public Accounting Firm.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of Spectra Energy Corp:

We have audited the accompanying consolidated balance sheets of Spectra Energy Corp and subsidiaries (the Company) as of December 31, 2007 and 2006, and the related consolidated statements of operations, stockholders /member s equity and comprehensive income, and cash flows for each of the three years in the period ended December 31, 2007. Our audits also included the financial statement schedule listed in the Index at Item 15. We also have audited the Company s internal control over financial reporting as of December 31, 2007, 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 these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management s Annual Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on these financial statements and financial statement schedule and an opinion on the Company s internal control over financial reporting 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 and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide 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, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Spectra Energy Corp and subsidiaries as of December 31, 2007 and 2006, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2007, in

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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, present fairly, in all material respects, the information set forth therein. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, based on the criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

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 Note 1 to the consolidated financial statements, in 2007 the Company changed its method of accounting for income tax positions as a result of adopting *FIN 48, Accounting for Uncertainty in Income Taxes an Interpretation of FASB Statement No. 109.*

As discussed in Note 1 to the consolidated financial statements, on January 2, 2007, Duke Energy Corporation (Duke Energy) completed the spin-off of Spectra Energy Corp. Duke Energy contributed its ownership interests in Spectra Energy Capital, LLC to Spectra Energy Corp and all of the outstanding common stock of Spectra Energy Corp was distributed to Duke Energy s shareholders.

/s/ Deloitte & Touche LLP

Houston, Texas

February 28, 2008

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SPECTRA ENERGY CORP

CONSOLIDATED STATEMENTS OF OPERATIONS

(In millions, except per-share amounts)

	Years Ended December 31,		
	2007	**2006**	**2005**
Operating Revenues			
Transportation, storage and processing of natural gas	$ 2,238	$ 2,126	$ 2,052
Distribution of natural gas	1,664	1,623	1,553
Sales of natural gas and natural gas liquids	601	531	5,547
Other	239	252	302
Total operating revenues	4,742	4,532	9,454
Operating Expenses			
Natural gas and petroleum products purchased	1,416	1,435	5,821
Operating, maintenance and other	1,161	1,202	1,338
Depreciation and amortization	525	489	611
Property and other taxes	209	208	228
Impairments and other charges	2		125
Total operating expenses	3,313	3,334	8,123
Gains on Sales of Other Assets and Other, net	13	47	522
Operating Income	1,442	1,245	1,853
Other Income and Expenses			
Equity in earnings of unconsolidated affiliates	596	609	355
Gains (losses) on sales and impairments of equity method investments		(3)	1,245
Gain on sale of subsidiary stock		15	
Other income and expenses, net	53	115	68
Total other income and expenses	649	736	1,668
Interest Expense	633	605	675
Minority Interest Expense	71	45	511
Earnings From Continuing Operations Before Income Taxes	1,387	1,331	2,335
Income Tax Expense From Continuing Operations	443	395	926
Income From Continuing Operations	944	936	1,409
Income (Loss) From Discontinued Operations, net of tax	13	308	(731)
Income Before Cumulative Effect of Change in Accounting Principle	957	1,244	678
Cumulative Effect of Change in Accounting Principle, net of tax and minority interest			(4)

Net Income	$ 957	$ 1,244	$ 674
Common Stock Data			
Weighted-average shares outstanding			
Basic	632	n/a(a)	n/a(a)
Diluted	635	n/a	n/a
Earnings per share from continuing operations			
Basic and Diluted	$ 1.49	n/a	n/a
Earnings per share-total			
Basic and Diluted	$ 1.51	n/a	n/a
Dividends per share	$ 0.88	n/a	n/a

(a) not applicable

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SPECTRA ENERGY CORP

CONSOLIDATED BALANCE SHEETS

(In millions)

	December 31, 2007	2006
ASSETS		
Current Assets		
Cash and cash equivalents	$ 94	$ 299
Receivables (net of allowance for doubtful accounts of $22 at December 31, 2007 and $13 at December 31, 2006)	907	779
Inventory	287	397
Other	91	150
Total current assets	1,379	1,625
Investments and Other Assets		
Investments in and loans to unconsolidated affiliates	1,780	1,618
Goodwill	3,948	3,507
Other	631	232
Total investments and other assets	6,359	5,357
Property, Plant and Equipment		
Cost	18,154	15,639
Less accumulated depreciation and amortization	3,854	3,245
Net property, plant and equipment	14,300	12,394
Regulatory Assets and Deferred Debits	932	969
Total Assets	$ 22,970	$ 20,345

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SPECTRA ENERGY CORP

CONSOLIDATED BALANCE SHEETS

(In millions, except per-share amounts)

	December 31, 2007	2006
LIABILITIES AND STOCKHOLDERS / MEMBER S EQUITY		
Current Liabilities		
Accounts payable	$ 363	$ 246
Notes payable and commercial paper	715	349
Taxes accrued	85	214
Interest accrued	146	149
Current maturities of long-term debt	338	550
Other	775	850
Total current liabilities	2,422	2,358
Long-term Debt	8,345	7,726
Deferred Credits and Other Liabilities		
Deferred income taxes	2,883	2,980
Regulatory and other	1,657	1,077
Total deferred credits and other liabilities	4,540	4,057
Commitments and Contingencies		
Minority Interests	806	565
Stockholders / Member s Equity		
Preferred stock, $0.001 par, 22 million shares authorized, no shares outstanding at December 31, 2007 and 2006		
Common stock, $0.001 par, 1 billion shares authorized, 632 million and 1 thousand shares outstanding at December 31, 2007 and 2006, respectively	1	
Additional paid-in capital	4,658	
Retained earnings	368	
Member s equity		4,598
Accumulated other comprehensive income	1,830	1,041
Total stockholders / member s equity	6,857	5,639
Total Liabilities and Stockholders / Member s Equity	$ 22,970	$ 20,345

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SPECTRA ENERGY CORP

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In millions)

	Years Ended December 31,		
	2007	**2006**	**2005**
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$ 957	$ 1,244	$ 674
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	534	606	774
Gains on sales of investments in commercial and multi-family real estate, equity investments and other assets		(509)	(1,955)
Impairment charges		48	159
Deferred income taxes	110	104	(240)
Minority interest	71	60	538
Equity in earnings of unconsolidated affiliates	(596)	(712)	(479)
Distributions from unconsolidated affiliates	569	707	473
Decrease (increase) in			
Receivables	59	167	(243)
Inventory	147	115	(74)
Other current assets	14	1,288	(435)
Increase (decrease) in			
Accounts payable	(93)	(690)	126
Taxes accrued	(61)	53	56
Other current liabilities	(198)	(461)	558
Capital expenditures for residential real estate		(322)	(355)
Cost of residential real estate sold		143	294
Other, assets	(36)	(796)	1,088
Other, liabilities	(10)	(351)	106
Cumulative effect of change in accounting principle			4
Net cash provided by operating activities	1,467	694	1,069
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures	(1,202)	(987)	(997)
Investment in and loans to unconsolidated affiliates	(285)	(87)	(23)
Acquisitions, net of cash acquired	(14)	(89)	(294)
Purchases of available-for-sale securities	(1,550)	(9,290)	(30,918)
Proceeds from sales and maturities of available-for-sale securities	1,405	9,775	30,706
Net proceeds from the sales of equity investments and other assets, and sales of and collections on notes receivable	15	2,025	2,372
Proceeds from the sales of commercial and multi-family real estate		254	372
Settlement of net investment hedges and other investing derivatives		(163)	(296)
Distributions from unconsolidated affiliates	87	152	383
Other		(21)	(64)
Net cash provided by (used in) investing activities	(1,544)	1,569	1,241
CASH FLOWS FROM FINANCING ACTIVITIES			
Proceeds from the issuance of long-term debt	783	1,799	543
Payments for the redemption of long-term debt	(981)	(1,662)	(840)
Net increase in notes payable and commercial paper	366	261	15
Distributions to minority interests	(57)	(304)	(861)
Contributions from minority interests	9	247	779
Proceeds from issuances of subsidiary stock	230	104	110
Dividends paid	(558)		
Distributions and advances to parent		(2,450)	(2,073)

Cash associated with operations transferred to Duke Energy		(427)	
Other	17	(22)	(14)
Net cash used in financing activities	(191)	(2,454)	(2,341)
Effect of exchange rate changes on cash	63	(1)	6
Net decrease in cash and cash equivalents	(205)	(192)	(25)
Cash and cash equivalents at beginning of period	299	491	516
Cash and cash equivalents at end of period	$ 94	$ 299	$ 491
Supplemental Disclosures			
Cash paid for interest, net of amount capitalized	$ 627	$ 679	$ 833
Cash paid for income taxes	$ 393	$ 238	$ 486

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SPECTRA ENERGY CORP

CONSOLIDATED STATEMENTS OF STOCKHOLDERS /MEMBER S

EQUITY AND COMPREHENSIVE INCOME

(In millions)

					Accumulated Other Comprehensive Income				
	Common Stock	Additional Paid-in Capital	Retained Earnings	Member Equity	Foreign Currency Translation Adjustments	Net Gains (Losses) on Cash Flow Hedges	Minimum Pension Liability Adjustment	Other	Total
December 31, 2004	$	$	$	$ 11,224	$ 539	$ 530	$ (20)	$	$ 12,273
Net income				674					674
Other comprehensive income									
Foreign currency translation adjustments					244				244
Net unrealized gains on cash flow hedges(a)						409			409
Reclassification of cash flow hedges into earnings(b)						(1,025)			(1,025)
Minimum pension liability adjustment							(40)		(40)
Net unrealized gains on SFAS 115 securities								19	19
Total comprehensive income									281
Advances from parent converted to equity				761					761
Capital contributions from parent				269					269
Distribution to parent				(2,100)					(2,100)
Other, net				20					20
December 31, 2005				10,848	783	(86)	(60)	19	11,504
Net income				1,244					1,244
Other comprehensive income									
Foreign currency translation adjustments					106				106
Net unrealized losses on cash flow hedges(a)						(6)			(6)
Reclassification of cash flow hedges into earnings(b)						39			39
Net unrealized gains on SFAS 115 securities(c)								14	14
Reclassification of SFAS 115 investments into earnings(d)								(33)	(33)
Transfer of taxes on net investment hedge and other hedges from parent					62	7			69
Transfer of various entities to affiliate					205				205
Transfer of Midwestern assets to affiliate(e)						40			40
Minimum pension liability adjustment(f)							(1)		(1)
Total comprehensive income									1,677
Transfer of Midwestern assets to affiliate				(1,462)					(1,462)
Transfer of Bison to affiliate				(60)					(60)
Forgiveness of advances to parent				(602)					(602)
Distribution to parent, net				(796)					(796)
Distribution to parent associated with sale of Crescent				(1,602)					(1,602)
Transfer of non-gas entities to affiliate				(2,952)					(2,952)
Pension adjustment SFAS 158 transition(g)							61	(109)	(48)

Other, net				(20)				(20)
December 31, 2006				4,598	1,156	(6)	(109)	5,639
Net income			957					957
Other comprehensive income								
Foreign currency translation adjustments					877			877
Reclassification of cash flow hedges into earnings(b)						(2)		(2)
Pension and benefits impact per SFAS 158							14	14
Total comprehensive income								1,846
Conversion to Spectra Energy Corp	1	4,597		(4,598)				
FIN 48 implementation			(26)					(26)
Transfer of net assets and liabilities from Duke Energy		12					(100)	(88)
Common stock dividends			(558)					(558)
Effect of changing measurement date per SFAS 158			(5)					(5)
Stock-based compensation		49						49
December 31, 2007	$ 1	$ 4,658	$ 368	$	$ 2,033	$ (8)	$ (195)	$ 6,857

(a) Net of $3 million tax benefit in 2006 and $234 million tax expense in 2005.
(b) Net of $1 million tax benefit in 2007, $20 million tax expense in 2006 and $584 million tax benefit in 2005.
(c) Net of $8 million tax expense in 2006 and $10 million tax expense in 2005.
(d) Net of $18 million tax benefit in 2006.
(e) Net of $24 million tax expense in 2006.
(f) Net of $27 million tax benefit in 2005.
(g) Net of $27 million tax benefit in 2006.

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SPECTRA ENERGY CORP

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1. Summary of Operations and Significant Accounting Policies

Nature of Operations. Spectra Energy Corp, through its subsidiaries and equity affiliates (collectively, Spectra Energy), owns and operates a large and diversified portfolio of complementary natural gas-related energy assets. Spectra Energy operates in three key areas of the natural gas industry: transmission and storage, distribution, and gathering and processing. Spectra Energy provides transportation and storage of natural gas to customers in various regions of the Northeastern and Southeastern United States, the Maritime Provinces in Canada and the Pacific Northwest in the United States and Canada, and in the province of Ontario, Canada. Spectra Energy also provides natural gas sales and distribution services to retail customers in Ontario, and natural gas gathering and processing services to customers in Western Canada. In addition, Spectra Energy owns a 50% interest in DCP Midstream, LLC (DCP Midstream), one of the largest natural gas gatherers and processors in the United States.

Spin-off from Duke Energy Corporation. On January 2, 2007, Duke Energy Corporation (Duke Energy) completed the spin-off of Spectra Energy. Duke Energy contributed the natural gas businesses, primarily comprised of the Natural Gas Transmission and Field Services business segments of Duke Energy that were owned through Duke Energy s then wholly owned subsidiary, Spectra Energy Capital, LLC (Spectra Capital). Duke Energy contributed its ownership interests in Spectra Capital to Spectra Energy and all of the outstanding common stock of Spectra Energy was distributed to Duke Energy s shareholders. Duke Energy s shareholders received one share of Spectra Energy common stock for every two shares of Duke Energy common stock, resulting in the issuance of approximately 631 million shares of Spectra Energy on January 2, 2007.

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In conjunction with the spin-off, on January 2, 2007, Duke Energy transferred to Spectra Energy the assets and liabilities, including related tax effects, associated with Spectra Energy s employee benefits and captive insurance positions, as well as miscellaneous corporate assets and liabilities. The net effect of these non-cash transfers is reflected as an increase of $12 million to Additional Paid-in Capital and a decrease of $100 million to Accumulated Other Comprehensive Income in the Consolidated Statement of Stockholders Equity and Comprehensive Income during the year ended December 31, 2007. The following summarizes the effect on the Consolidated Balance Sheet in 2007 as a result of the transfers:

	Increase (Decrease) to Equity (in millions)
Receivables	$ (9)
Other assets	186
Taxes accrued	(5)
Other current liabilities	(65)
Deferred income taxes	94
Other liabilities	(289)
Net equity decrease	$ (88)

See also Notes 11 and 22 for further discussion of captive insurance and employee benefit plans.

Other Significant Changes. On April 1, 2006, Spectra Energy transferred the operations of its wholly owned captive insurance subsidiary, Bison Insurance Company Limited (Bison), to Duke Energy. Accordingly, Bison s operations are not included in Spectra Energy s results of operations, financial position or cash flows subsequent to its transfer to Duke Energy. Due to continuing involvement between Bison and Spectra Energy entities, the results of operations of Bison do not qualify for discontinued operations treatment.

Additionally, in April 2006, Spectra Energy indirectly transferred to Duke Energy Ohio, Inc. (Duke Energy Ohio), its ownership interest in Duke Energy North America s (DENA s) Midwestern assets, representing a mix of combined cycle and peaking plants. In connection with this transfer, Spectra Energy transferred to Duke Energy Ohio approximately $1.6 billion of assets at their carrying value and approximately $0.1 billion of liabilities at their carrying value, for a net transfer of approximately $1.5 billion. This transfer has been accounted for as a capital distribution at historical cost. The results of operations for DENA s Midwestern assets have been reflected as discontinued operations in the accompanying Consolidated Statements of Operations up through the date of transfer.

On September 7, 2006, Spectra Energy deconsolidated Crescent Resources, LLC (Crescent) due to a reduction in ownership and its inability to exercise control over Crescent. See Note 9 for further discussion. Crescent was accounted for as an equity method investment from the date of deconsolidation. Crescent was one of the entities contributed by Spectra Energy to Duke Energy in anticipation of the spin-off.

Effective July 1, 2005, Spectra Energy deconsolidated DCP Midstream, LLC (DCP Midstream) due to a reduction in ownership and its inability to exercise control over DCP Midstream. See Note 3 for further discussion. DCP Midstream has been subsequently accounted for as an equity method investment.

Basis of Presentation. The accompanying consolidated financial statements include the accounts of Spectra Energy Corp, its majority-owned subsidiaries where Spectra Energy has control and those variable interest entities, if any, where Spectra Energy is the primary beneficiary. As a result of the spin-off of the natural gas businesses of Duke Energy to Duke Energy s shareholders, Spectra Capital is treated as the predecessor entity to Spectra Energy for financial statement reporting purposes. Accordingly, the 2006 and 2005 information presented herein for Spectra Energy is that of Spectra Capital. Additionally, in anticipation of the spin-off, and as

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further described in Note 9, Spectra Capital implemented an internal reorganization in December 2006 in which the operations and assets of Spectra Capital that were not associated with the natural gas businesses were contributed by Spectra Capital to Duke Energy or its subsidiaries. The 2006 and 2005 results of operations of most of these transferred businesses are included in Income From Discontinued Operations, Net of Tax in the accompanying Consolidated Statements of Operations. Corporate service companies that were transferred to Duke Energy in December 2006 are reported within continuing operations since corporate services continue to be provided at Spectra Energy to support operations. Information presented for 2006 and 2005 in the Consolidated Statements of Cash Flows does not include any reclassifications or adjustments to amounts historically reported for these transferred businesses.

Use of Estimates. To conform with 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 to Consolidated Financial Statements. Although these estimates are based on management s best available knowledge at the time, actual results could differ.

Reclassifications. As a result of the spin-off and the related realignment of Spectra Capital s business segments as discussed in Note 4, the components of Operating Revenues on the consolidated Statements of Operations for the 2006 period have been reclassified to conform to the current reporting presentation. In addition, $112 million of balancing gas has been reclassified from Deferred Debits to Other Assets on the Consolidated Balance Sheet at December 31, 2006 to conform to the current reporting presentation.

Cash and Cash Equivalents. Highly liquid investments with original maturities of three months or less at the date of acquisition, except for the investments that are pledged as collateral against long-term debt as discussed below, are considered cash equivalents.

Inventory. Inventory consists primarily of natural gas and natural gas liquids (NGLs) held in storage for transmission and processing, and also includes materials and supplies. Natural gas inventories primarily relate to the distribution business in Canada and are valued at costs approved by the regulator, the Ontario Energy Board (OEB). The difference between the approved price and the actual cost of gas purchased is recorded in either accounts receivable or other current liabilities for future disposition with customers, subject to approval by the OEB. The remaining inventory is recorded at cost, primarily using average cost. The components of inventory are as follows:

	December 31,	
	2007	2006
	(in millions)	
Natural gas	$ 154	$ 290
Materials and supplies	108	90
Petroleum products	25	17
Total inventory	$ 287	$ 397

Natural Gas Imbalances. The Consolidated Balance Sheets include in-kind balances as a result of differences in gas volumes received and delivered for customers. Since settlement of imbalances is in-kind, changes in the balances do not have an effect on Spectra Energy s Consolidated Statements of Cash Flows. Accounts Receivable includes $119 million as of December 31, 2007 and $113 million as of December 31, 2006. Other Current Liabilities includes $136 million as of December 31, 2007 and $118 million as of December 31, 2006, related to gas imbalances. Natural gas volumes owed to or by Spectra Energy are valued at natural gas market index prices as of the balance sheet dates.

Accounting for Risk Management and Hedging Activities and Financial Instruments. During 2005 and 2006, Spectra Energy used a number of different derivative and non-derivative instruments in connection

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with its commodity price, interest rate and foreign currency risk management activities, such as swaps, futures, forwards and options. In 2007, these derivative instruments were limited to interest rate positions, a small percentage of gas purchase hedges around the regulated operations at Union Gas Limited (Union Gas) and commodity derivatives at DCP Midstream. All derivative instruments not designated as hedges or qualifying for the normal purchases and normal sales exception under Statement of Financial Accounting Standards (SFAS) No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended, are recorded on the Consolidated Balance Sheets at fair value. Cash inflows and outflows related to derivative instruments, except 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 net investment hedges and derivatives related to other investing activities are a component of investing cash flows.

Where Spectra 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, are met, Spectra Energy presents its derivative assets and liabilities, and accompanying receivables and payables, on a net basis in the accompanying Consolidated Balance Sheets. Subsequent to the transfer of businesses to Duke Energy in 2006, Spectra Energy does not have any significant outstanding derivative instruments and does not participate in significant master netting arrangements in the normal course of its business.

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, Spectra Energy prepares documentation of the hedge in accordance with SFAS No. 133 and assesses whether the hedge contract is highly effective in offsetting changes in cash flows or fair values of hedged items. Spectra 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 Stockholders /Member s Equity and Comprehensive Income as Accumulated Other Comprehensive Income (AOCI) until earnings are affected by the hedged transaction. Spectra 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, Spectra 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. In the event the hedge is not effective, there is no offsetting gain or loss recognized in earnings. 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.

Fair value gains and losses on gas supply hedge positions at Union Gas are recognized as a regulatory asset or liability, as applicable, on the Consolidated Balance Sheets, pending recovery or refund as approved by the regulator as part of Union Gas gas cost recovery mechanisms.

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

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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.

Investments. Spectra Energy may actively invest a portion of its available cash and restricted cash balances in various financial instruments, including taxable or tax-exempt debt securities that frequently have stated maturities of 20 years or more. These instruments provide for a high degree of liquidity through features such as 7, 28, and 35 day auctions which allow for the redemption of the investments at their face amounts plus earned income. In addition, Spectra Energy invests in short-term money market securities, some of which are restricted due to debt collateral and insurance requirements. Spectra Energy has classified all investments that are debt securities with maturity dates over one year as available-for-sale under SFAS No. 115, Accounting For Certain Investments in Debt and Equity Securities, and they are carried at fair market value. Investments in money-market securities are accounted for at cost, as the carrying values approximate market values due to the short-term maturities, floating interest rates and minimal 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. The cost of securities sold is determined using the specific identification method. 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.

Goodwill. Spectra Energy evaluates goodwill for potential impairment under the guidance of SFAS No. 142, Goodwill and Other Intangible Assets. Under this standard, goodwill is subject to an annual test for impairment. Spectra 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, Spectra Energy performs the annual review for goodwill impairment at the reporting unit level, which Spectra 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.

Spectra Energy completed its annual goodwill impairment test as of August 31, 2007 and no impairments were identified. Spectra Energy primarily uses a discounted cash flow analysis to determine fair value for each reporting unit. Key assumptions in the determination of fair value include the use of an appropriate discount rate and estimated future cash flows. In estimating cash flows, Spectra Energy incorporates expected long-term growth rates, regulatory stability, the ability to renew contracts, commodity prices (where appropriate), and foreign currency exchange rates, as well as other factors that affect its revenue, expense and capital expenditure projections.

Property, Plant and Equipment. Property, plant and equipment are stated at historical cost less accumulated depreciation. Spectra 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 or increase the expected output 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 incurred. Depreciation is generally computed over the asset s estimated useful life using the straight-line method. The composite weighted-average depreciation rates, including depreciation associated with businesses included in discontinued operations, were 3.14% for 2007, 3.32% for 2006 and 3.60% for 2005. See also Allowance for Funds Used During Construction (AFUDC) discussed below.

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When Spectra 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.

Asset Retirement Obligations. Spectra Energy recognizes asset retirement obligations (AROs) in accordance with SFAS No. 143, Accounting For Asset Retirement Obligations, 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 47, Accounting for Conditional Asset Retirement Obligations, for conditional AROs in which the timing or method of settlement are conditional on a future event that may or may not be within the control of Spectra 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.

Long-Lived Asset Impairments, Assets Held For Sale and Discontinued Operations. Spectra 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.

Spectra Energy uses the criteria in SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets, 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 Sheet. When an asset or asset group meets the SFAS No. 144 criteria for classification as held for sale within the Consolidated Balance Sheet, Spectra Energy does not retrospectively adjust prior period balance sheets to conform to current year presentation.

Spectra Energy uses the criteria in SFAS No. 144 and Emerging Issues Task Force (EITF) 03-13, Applying the Conditions in Paragraph 42 of FASB Statement No. 144 in Determining Whether to Report Discontinued Operations, to determine whether components of Spectra 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, Spectra Energy must not have significant continuing involvement in the operations after the disposal (i.e. Spectra 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 Spectra Energy s ongoing operations (i.e. Spectra 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

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results of operations for the current and prior periods, including any related impairments, are reflected as Income (Loss) 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 and Other, Net. Impairments for all other long-lived assets, excluding goodwill, are recorded as Impairment and Other Charges.

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. Spectra 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. Undiscounted 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. Spectra Energy accounts for certain of its regulated operations under the provisions of SFAS No. 71, Accounting for the Effects of Certain Types of Regulation. 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, Spectra 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 and recent rate orders applicable to other regulated entities. 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. Spectra Energy periodically evaluates the applicability of SFAS No. 71, and considers factors such as regulatory changes and the effect of competition. If cost-based regulation ends or competition increases, Spectra Energy may have to reduce its asset balances to reflect a market basis less than cost and write-off the associated regulatory assets and liabilities. See Note 5 for further discussion.

Captive Insurance Reserves. Prior to April 1, 2006, Spectra Energy had captive insurance subsidiaries which provided insurance coverage to Spectra 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 included provisions for estimated losses incurred but not yet reported, as well as provisions for known claims which have been estimated on a claims-incurred basis. Incurred but not yet reported 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. Subsequent to April 1, 2006, Spectra Energy was provided insurance coverage through a captive insurance company of its parent, Duke Energy, as well as certain third parties. Effective January 2, 2007, this coverage and the associated insurance assets and liabilities applicable to the ongoing operations of Spectra Energy were transferred to a new captive insurance subsidiary of Spectra Energy.

Prior to January 1, 2007, Spectra Energy s captive insurance entities also had reinsurance coverage, which provided reimbursement to Spectra Energy for certain losses above a per incident and/or aggregate retention. Spectra Energy s captive insurance entities also had an aggregate stop-loss insurance coverage, which provided reimbursement from third parties to Spectra Energy for its paid losses above certain per-line-of-coverage aggregate amounts during a policy year. Spectra Energy recognizes an insurance receivable for recovery of incurred losses under its insurance coverage once realization of the receivable is deemed probable.

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Guarantees. Spectra 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. In accordance with FIN 45, upon issuance or modification of a guarantee on or after January 1, 2003, Spectra 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. Spectra 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.

Stock-Based Compensation. Effective January 1, 2006, Spectra Energy adopted the provisions of SFAS No. 123(R), Share-Based Payment. See Note 21 for further discussion. 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.

Spectra Energy elected to adopt the modified prospective application method as provided by SFAS No. 123(R), and accordingly, financial statement amounts for periods prior to January 1, 2006 in this report have not been restated. There were no modifications to outstanding stock options prior to the adoption of SFAS 123(R). Spectra Energy historically had been allocated its proportionate share of stock-based compensation expense from Duke Energy.

In 2005, Spectra Energy applied 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 during these years 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 from the transportation, storage, distribution and sales of natural gas, and from the sales of NGLs 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, 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.

Allowance for Funds Used During Construction (AFUDC). AFUDC, which represents the estimated debt and equity costs of capital funds necessary to finance the construction of certain 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, Spectra 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 $40 million in 2007 (an equity component of $22 million and an interest expense component of $18 million), $21 million in 2006 (an equity component of $11 million and an interest expense component of $10 million) and $17 million in 2005 (an equity component of $8 million and an interest expense component of $9 million).

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Preliminary Project Costs. Project development costs, including expenditures for preliminary surveys, plans, investigations, environmental studies, regulatory applications and other costs incurred for the purpose of determining the feasibility of capital expansion projects, are initially included in operating expenses for U.S. rate-regulated enterprises that apply the principles of SFAS No. 71. If and when it is determined that recovery of such costs through regulated revenues of the completed project is probable, the inception-to-date costs of the project are recognized as Property, Plant and Equipment in accordance with the provisions of SFAS No. 71 and operating expenses are reduced.

Accounting For Sales of Stock by a Subsidiary. Spectra Energy accounts for sales of stock by a subsidiary under Staff Accounting Bulletin (SAB) No. 51, Accounting for Sales of Stock of a Subsidiary. 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. Spectra 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 2006, Spectra Energy recognized a gain of $15 million related to the sale of securities of the Spectra Energy Income Fund (the Income Fund), formerly the Duke Energy Income Fund. See Note 3 for further discussion.

Income Taxes. Deferred income taxes are recognized for differences between the financial reporting and tax bases of assets and liabilities at enacted statutory tax rates in effect for the years in which the differences are expected to reverse. The effect on deferred taxes of a change in tax rates is recognized in income in the period that includes the enactment date. Actual income taxes could vary from these estimates due to future changes in income tax law or results from the final review of tax returns by federal, state or foreign tax authorities.

As a result of Duke Energy s merger with Cinergy Corp (Cinergy), Spectra Energy and its subsidiaries entered into a tax sharing agreement with Duke Energy, effective April 1, 2006, where the separate return method was used to allocate income taxes to Duke Energy s subsidiaries based on the results of their operations. The accounting for income taxes essentially represents the income taxes that Spectra Energy would incur if Spectra Energy were a separate company filing its own tax return as a C-Corporation. Prior to entering into this tax sharing agreement, Spectra Energy was a pass-through entity for U.S. income tax purposes.

Spectra Energy adopted FIN 48, Accounting for Uncertainty in Income Taxes, an Interpretation of FAS 109, on January 1, 2007. The financial statement effects on tax positions are recognized in the period in which it is more-likely-than-not that the position will be sustained upon examination, the position is effectively settled or when the statute of limitations to challenge the position has expired. Interest and penalties related to unrecognized tax benefits are recorded as interest expense and other expense, respectively.

Segment Reporting. SFAS No. 131, Disclosures about Segments of an Enterprise and Related Information, 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 Spectra Energy s defined business segments. The description of Spectra 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, is presented in Note 4.

Foreign Currency Translation. The local currencies of Spectra Energy s foreign operations, which represent Canadian operations subsequent to the spin-off from Duke Energy on January 2, 2007, have been determined to be their functional currencies, except for certain foreign operations (prior to 2007) included in discontinued operations whose functional currency has been determined to be the U.S. Dollar, based on an

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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 Spectra 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.

Consolidated Statements of Cash Flows. Spectra 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. 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 Unconsolidated Affiliates. Spectra Energy considers dividends received from unconsolidated affiliates which do not exceed cumulative equity in earnings subsequent to the date of investment to be 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 to be a return of investment and are classified as investing activities.

New Accounting Pronouncements 2007. The following new accounting pronouncements were adopted during 2007 and the effect of such adoption, if applicable, has been presented in the accompanying Consolidated Financial Statements:

SFAS No. 155, Accounting for Certain Hybrid Financial Instruments an amendment of FASB Statements No. 133 and 140. 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 was effective for Spectra 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. The adoption of SFAS No. 155 did not have an impact on Spectra Energy s consolidated results of operations, cash flows or financial position.

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 Spectra Energy has concluded there is a level of uncertainty with respect to the recognition in its financial statements. Spectra Energy implemented FIN 48 effective January 1, 2007. As discussed further in Note 8 the implementation resulted in a cumulative effect decrease of $26 million to beginning Retained Earnings on the Consolidated Statements of Stockholders Equity and Comprehensive Income. Uncertain tax positions on

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consolidated or combined tax returns filed by Duke Energy which are now indemnified by Spectra Energy, were recorded as payables to Duke Energy.

FSP No. FAS 123(R)-5, Amendment of FASB Staff Position FAS 123(R)-1. In October 2006, the FASB staff issued FSP No. FAS 123-5 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). In August 2005, the FASB 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 GAAP. 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. The guidance in this FSP was effective for Spectra Energy as of January 1, 2007. The adoption of FSP No. FAS 123(R)-5 did not have a material effect on consolidated results of operations, financial position or cash flows.

FSP No. AUG AIR-1, Accounting for Planned Major Maintenance Activities. In September 2006, the FASB 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 was effective for Spectra Energy as of January 1, 2007 and was applied retrospectively for all financial statements presented. The adoption of FSP No. AUG AIR-1 did not have an effect on Spectra Energy s consolidated results of operations, financial position or cash flows.

2006. The following significant accounting pronouncements were adopted during 2006 and the effect of such adoption has been presented in the accompanying Consolidated Financial Statements:

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). 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. Spectra Energy was 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. The adoption of SFAS No. 158 recognition and disclosure provisions resulted in an increase in total assets of approximately $21 million (consisting of an increase in deferred tax assets of $27 million, offset by a decrease in intangible assets of $6 million), an increase in total liabilities of approximately $69 million and an increase in Accumulated Other Comprehensive Income, Net of Tax, of approximately $48 million as of December 31, 2006.

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, Spectra 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. Spectra Energy adopted the change in measurement date effective January 1, 2007 by re-measuring 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 was recognized, net of tax,

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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 were recognized, net of tax, as an adjustment to Other Comprehensive Income.

2005. The following significant accounting pronouncement was adopted during 2005 and the effect of such adoption has been presented in the accompanying Consolidated Financial Statements:

FIN 47 Accounting for Conditional Asset Retirement Obligations. In 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. 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 Spectra Energy as of December 31, 2005, and resulted in an increase in assets of $7 million, an increase in liabilities of $11 million and a net-of-tax cumulative effect adjustment to earnings of $4 million.

Pending. The following new accounting pronouncements have been issued, but have not yet been adopted as of December 31, 2007:

SFAS No. 157, Fair Value Measurements. 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 Spectra Energy s current practice for measuring and disclosing fair values under other accounting pronouncements that require or permit fair value measurements. For Spectra Energy, SFAS No. 157 is effective as of January 1, 2008 and must be applied prospectively except in certain cases. The adoption of SFAS No. 157 is not expected to materially affect Spectra Energy s consolidated results of operations, financial position or cash flows.

SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities. In February 2007, the FASB issued SFAS No. 159, which permits entities to choose to measure certain financial instruments at fair value. For Spectra Energy, SFAS No. 159 is effective as of January 1, 2008. Spectra Energy has determined it will not elect fair value measurements for financial assets and financial liabilities included in the scope of SFAS No. 159.

SFAS No. 141R, Business Combinations. In December 2007, the FASB issued SFAS No. 141R which replaces SFAS No. 141, Business Combinations. SFAS No. 141R requires the acquiring entity in a business combination to recognize all and only the assets acquired and liabilities assumed in the transaction, establishes the acquisition-date fair value as the measurement objective for all assets acquired and liabilities assumed, requires the acquirer to disclose to investors and other users all of the information they need to evaluate and understand the nature and financial effect of the business combination and further requires that acquisition-related costs, except for costs to issue debt or equity securities, be expensed in the period incurred. SFAS No. 141R applies prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008 and cannot be early adopted.

SFAS No. 160, Noncontrolling Interest in Consolidated Financial Statements. In December 2007, the FASB issued SFAS No. 160 which requires all entities to report noncontrolling (minority) interests in subsidiaries as equity in the consolidated financial statements. SFAS No. 160 eliminates the diversity that currently exists in accounting for transactions between an entity and noncontrolling interests by requiring they be treated as equity transactions. SFAS No. 160 is effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008 and early adoption is prohibited. Spectra Energy is currently evaluating the effect of adopting SFAS No. 160, and cannot currently estimate the effect it will have on its consolidated results of operations, financial position or cash flows.

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EITF 06-11 Accounting for Income Tax Benefits of Dividends on Share-Based Payment Awards. In June 2007, the FASB Emerging Issues Task Force (EITF) reached a consensus that a realized income tax benefit from dividends or dividend equivalents that are charged to retained earnings and are paid to employees for equity classified nonvested equity shares, nonvested equity share units and outstanding equity share options should be recognized as an increase to additional paid-in capital. The amount recognized in additional paid-in capital for the realized income tax benefit from dividends on those awards should be included in the pool of excess tax benefits available to absorb tax deficiencies on share-based payment awards. EITF 06-11 will be applied prospectively to the income tax benefits that result from dividends on equity-classified employee share-based payment awards that are declared after December 31, 2007. The effect of adopting EITF 06-11 is not expected to be material to Spectra Energy s consolidated results of operations, financial position or cash flows.

EITF 07-01 Accounting for Collaborative Arrangements. In December 2007, the FASB ratified a consensus reached by the EITF to define collaborative arrangements and to establish reporting requirements for transactions between participants in a collaborative arrangement and between participants in the arrangement and third parties. A collaborative arrangement is a contractual arrangement that involves a joint operating activity. These arrangements involve two (or more) parties who are both (a) active participants in the activity and (b) exposed to significant risks and rewards dependent on the commercial success of the activity. EITF 07-01 is effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years. An entity should report the effects of applying EITF 07-01 as a change in accounting principle through retrospective application to all prior periods presented for all arrangements existing as of the effective date. Spectra Energy is currently evaluating the effect of adopting EITF 07-01, but does not believe it will have a material effect on its consolidated results of operations, financial position or cash flows.

2. Spectra Energy Partners, LP Initial Public Offering

In July 2007, Spectra Energy completed its initial public offering (IPO) of Spectra Energy Partners, LP (Spectra Partners), a newly formed midstream energy master limited partnership. Spectra Energy contributed to Spectra Partners 100% of the ownership of East Tennessee Natural Gas, LLC, 50% of the ownership of Market Hub Partners, LLC, including the Moss Bluff and Egan natural gas storage operations, and a 24.5% interest in Gulfstream Natural Gas System, LLC. Spectra Partners issued 11.5 million common units to the public in the offering, representing 17% of Spectra Partners outstanding equity. Spectra Energy retained an 83% equity interest in Spectra Partners, including its common units, subordinated units and a 2% general partner interest and received total proceeds of approximately $345 million as a result of the transaction, including the debt issued as discussed below. Net cash of approximately $230 million was received by Spectra Partners upon closing of the IPO. Approximately $26 million of these proceeds was distributed to Spectra Energy, $194 million was used by Spectra Partners to purchase qualifying investment grade securities, and $10 million was retained by Spectra Partners to meet working capital requirements. Spectra Partners borrowed $194 million in term debt using the investment grade securities as collateral and borrowed an additional $125 million of revolving debt. Proceeds from these borrowings, totaling $319 million, were distributed to Spectra Energy.

In accordance with the Securities and Exchange Commission (SEC) Staff Accounting Bulletin No. 51, Accounting for Sales of Stock by a Subsidiary, recognition of a gain associated with such a sale is only appropriate if the class of securities sold by the subsidiary does not contain any preference over the subsidiary s other classes of securities. Since the common units of Spectra Partners have preferential cash distribution rights as compared to the subordinated units, Spectra Energy has deferred recognition of the gain associated with the sale of Spectra Partners common units until the subordinated units owned by Spectra Energy are converted into common units with rights equivalent to the remaining unitholders. The deferred gain totaled approximately $60 million at December 31, 2007 and is included in Regulatory and Other Deferred Credits and Other Liabilities in the Consolidated Balance Sheet.

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3. Acquisitions and Dispositions

Acquisitions (excluding acquisitions made by discontinued operations that are discussed in Note 9). Spectra 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 98-3, Determining Whether a Nonmonetary Transaction Involves Receipt of Productive Assets or of a Business, is recorded as goodwill. The allocation of the purchase price may be adjusted if additional information is received during the allocation period, which generally does not exceed one year from the consummation date. This allocation period may be longer for certain income tax items.

In August 2005, U.S. Transmission acquired natural gas storage and pipeline assets in Southwest Virginia and an additional 50% interest in Saltville Gas Storage, L.L.C. from units of AGL Resources for $62 million. This transaction increased U.S. Transmission s ownership percentage of Saltville Gas Storage, L.L.C. to 100%. No goodwill was recorded as a result of this acquisition.

In August 2005, Western Canada Transmission & Processing acquired the Empress System natural gas processing and NGL marketing business from ConocoPhillips for $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.

The pro forma results of operations for Spectra Energy as if those acquisitions occurred as of the beginning of the periods presented do not materially differ from reported results.

Dispositions (excluding dispositions made by discontinued operations that are discussed in Note 9). For the year ended December 31, 2006, the sale of other assets and businesses (which excludes discontinued operations that are discussed in Note 9) resulted in $80 million in proceeds and net pre-tax gains of $47 million recorded in Gains on Sales of Other Assets, net on the Consolidated Statements of Operations. Significant sales of other assets and businesses during 2006 are detailed as follows:

U.S. 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 on Sales of Other Assets, Net. In addition, U.S. Transmission s sale of stock, received as consideration for the settlement of a customer s transportation contract, resulted in proceeds of $29 million which is reflected in Other, Assets within Cash Flows from Operating Activities and a pre-tax gain of $29 million, of which $28 million was recorded in Gains on Sales of Other Assets, Net and $1 million was recorded in Other Income and Expenses, Net. See Note 11 for further discussion.

As a result of a settlement of a property insurance claim, U.S. Transmission received proceeds of $30 million and recognized a pre-tax gain of $10 million, which was recorded in Gains on Sales of Other Assets, Net.

In September 2006, the Income Fund created in 2005 sold 9 million previously unissued Trust Units for total proceeds of $94 million, net of commissions and other expenses of issuance, which is included in Proceeds from Issuances of Subsidiary Stock within Cash Flows from Financing Activities. The sale of these units reduced Spectra 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, Spectra Energy recognized a $15 million pre-tax SAB No. 51 gain on the sale of subsidiary stock, which is classified in Gain on Sale of Subsidiary Stock. The proceeds from the offering plus the draw down of 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. from Spectra Energy. There were no deferred taxes recorded as a result of this transaction.

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For the year ended December 31, 2005, the sale of other assets, businesses and equity investments (which excludes assets held for sale as of December 31, 2005 and discontinued operations, both of which are discussed in Note 9) resulted in $2.3 billion in proceeds, pre-tax gains of $522 million recorded in Gains on Sales of Other Assets, Net and pre-tax gains of $1.2 billion recorded in Gains (Losses) on Sales and Impairments of Equity Method Investments. Significant sales of other assets and equity investments during 2005 are detailed as follows:

In February 2005, DCP Midstream 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 Spectra Energy sold its limited partner interest in TEPPCO LP for approximately $100 million. These transactions resulted in pre-tax gains of approximately $1.2 billion, which were recorded in Gains (Losses) on Sales and Impairments of Equity Method Investments. Minority Interest Expense of $343 million was recorded to reflect ConocoPhillips proportionate share in the pre-tax gain on sale of TEPPCO GP. Additionally, in July 2005, Spectra Energy completed the agreement with ConocoPhillips, Spectra Energy s co-equity owner in DCP Midstream, to reduce Spectra Energy s ownership interest in DCP Midstream from 69.7% to 50% (the DCP Midstream disposition transaction), which results in Spectra Energy and ConocoPhillips becoming equal 50% owners in DCP Midstream. Spectra Energy received, directly and indirectly through its ownership interest in DCP Midstream, a total of approximately $1.1 billion from ConocoPhillips and DCP Midstream, consisting of approximately $1.0 billion in cash and $0.1 billion of assets. The DCP Midstream disposition transaction resulted in a pre-tax gain of $575 million, which was recorded in Gains on Sales of Other Assets, Net. The DCP Midstream disposition transaction includes the transfer to Spectra Energy of DCP Midstream s Canadian natural gas gathering and processing facilities. Additionally, the DCP Midstream disposition transaction included the acquisition of ConocoPhillips interest in the Empress System. Subsequent to the closing of the DCP Midstream disposition transaction, effective on July 1, 2005, DCP Midstream is no longer consolidated into Spectra Energy s consolidated financial statements and is accounted for by Spectra Energy as an equity method investment. See Note 20 for the effects of this transaction on certain cash flow hedges. The Canadian natural gas gathering and processing facilities and the Empress System are included in the Western Canada Transmission & Processing segment.

In December 2005, the Income Fund, a Canadian income trust fund, was created to acquire all of the common shares of Spectra Energy Midstream Services Canada Corporation (Spectra Midstream) from a subsidiary of Spectra Energy. The Income Fund sold an approximate 40% ownership interest in Spectra Midstream for $110 million, which was included in Proceeds from Spectra Energy Income Fund within Cash Flows from Financing Activities. In January 2006, a subsequent greenshoe sale of additional ownership interests pursuant to an overallotment option in the Income Fund were sold for $10 million.

In December 2005, Commercial Power recorded a $70 million charge related to the termination of structured power contracts in the Southeast, which was recorded in Gains on Sales of Other Assets, Net.

See Note 9 for discussion of businesses acquired or disposed of during the years ended December 31, 2006 and 2005 that were included in the operations transferred to Duke Energy during 2006 and, accordingly, are included in Income (Loss) From Discontinued Operations, Net of Tax.

4. Business Segments

As a result of the reorganization and spin-off of Spectra Energy from Duke Energy on January 2, 2007, Spectra Energy now manages its business in four reportable segments: U.S. Transmission, Distribution, Western Canada Transmission & Processing and Field Services. The remainder of Spectra Energy s business operations is presented as Other, and consists of unallocated corporate costs, wholly owned captive insurance subsidiaries, employee benefit plan assets and liabilities, and other miscellaneous activities. Comparative 2006 and 2005 data has been re-cast to conform the business segment disclosures to the new segment structure.

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Spectra 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 business units are considered reportable segments under SFAS No. 131.

U.S. Transmission provides transportation and storage of natural gas for customers in various regions of the Eastern and Southeastern United States and the Maritime Provinces in Canada. The natural gas transmission and storage operations in the U.S. are primarily subject to the Federal Energy Regulatory Commission s (FERC s) rules and regulations.

Distribution provides retail natural gas distribution service in Ontario, Canada, as well as natural gas transportation and storage services to other utilities and energy market participants in Ontario, Quebec and the United States. These services are provided by Union Gas, and are primarily subject to the rules and regulations of the OEB.

Western Canada Transmission & Processing provides transportation of natural gas, natural gas gathering and processing services, and NGL extraction, fractionation, transportation, storage and marketing to customers in Western Canada and the northern tier of the United States. This segment conducts business primarily through the BC Pipeline and Field Services operations, the Empress System and the Midstream business, which owns a 46% interest in the operations of the Income Fund. BC Pipeline and Field Services operations are primarily subject to the rules and regulations of Canada s National Energy Board (NEB).

Field Services gathers and processes natural gas, and fractionates, markets and trades NGLs. It conducts operations through DCP Midstream, which is owned 50% by Spectra Energy and 50% by ConocoPhillips. Field Services gathers raw natural gas through gathering systems located in eight major natural gas producing regions: Permian Basin, Mid-Continent, Rocky Mountain, East Texas-North Louisiana, Barnett Shale, Gulf Coast, South Texas and Central Texas.

Commercial Power, which did not have any operations or net assets within Spectra Energy effective after December 31, 2005, consisted of a portion of Spectra Energy s operations formerly known as DENA. Commercial Power operated and managed power plants and related contractual positions in the Southeastern United States. Commercial Power s continuing operations consisted primarily of eight natural gas-fired merchant power plants in the Southeastern United States and certain other power and gas contracts (collectively, the Southeast Plants). Spectra Energy sold the Southeast Plants in 2004 and the remaining contracts in 2005, and remains reported as a business segment in 2005 as a result of continuing involvement identified at the time of the sale.

Spectra Energy s reportable segments offer different products and services and are managed separately as business units. Management evaluates segment performance based on earnings before interest and taxes (EBIT) from continuing operations, after deducting minority interest expense related to those profits.

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 Spectra 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.

Transactions between reportable segments are accounted for on the same basis as transactions with unaffiliated third parties.

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Business Segment Data

	Unaffiliated Revenues	Intersegment Revenues	Total Revenues	Segment EBIT/ Consolidated Earnings from Continuing Operations before Income Taxes	Depreciation and Amortization(a)	Capital and Investment Expenditures(a)	Segment Assets
				(in millions)			
2007							
U.S. Transmission	$ 1,535	$ 5	$ 1,540	$ 894	$ 217	$ 898	$ 8,763
Distribution	1,899		1,899	322	162	369	4,968
Western Canada Transmission & Processing	1,304		1,304	366	141	195	4,637
Field Services(b)				533			1,076
Total reportable segments	4,738	5	4,743	2,115	520	1,462	19,444
Other	4	27	31	(112)	5	39	3,876
Eliminations		(32)	(32)				(350)
Interest expense				(633)			
Interest income and other(c)				17			
Total consolidated	$ 4,742	$	$ 4,742	$ 1,387	$ 525	$ 1,501	$ 22,970
2006							
U.S. Transmission	$ 1,516	$ (13)	$ 1,503	$ 816	$ 203	$ 343	$ 7,611
Distribution	1,822		1,822	265	144	315	4,420
Western Canada Transmission & Processing	1,204		1,204	345	133	132	3,960
Field Services(b)				569			1,231
Total reportable segments	4,542	(13)	4,529	1,995	480	790	17,222
Other	(10)	39	29	(77)	9	40	3,299
Eliminations		(26)	(26)				(176)
Interest expense				(605)			
Interest income and other(c)				18			
Total consolidated	$ 4,532	$	$ 4,532	$ 1,331	$ 489	$ 830	$ 20,345
2005							
U.S. Transmission	$ 1,387	$ 66	$ 1,453	$ 840	$ 207	$ 388	
Distribution	1,725		1,725	277	129	172	
Western Canada Transmission & Processing	873	1	874	243	120	370	
Field Services(b)	5,618	(88)	5,530	1,946	143	86	
Commercial Power(d)				(70)			
Total reportable segments	9,603	(21)	9,582	3,236	599	1,016	
Other(d)	(149)	148	(1)	(250)	12	18	
Eliminations		(127)	(127)				
Interest expense				(675)			
Interest income and other(c)				24			
Total consolidated	$ 9,454	$	$ 9,454	$ 2,335	$ 611	$ 1,034	

(a) Excludes amounts associated with entities included in discontinued operations.
(b) In July 2005, Spectra Energy reduced its ownership interest in DCP Midstream from 69.7% to 50%. Field Services segment data includes DCP Midstream as a consolidated entity for periods prior to July 1, 2005 and as an equity method investment for periods after June 30, 2005.
(c) Other includes foreign currency transaction gains and losses, and additional minority interest expense not allocated to the segment results.
(d) Amounts associated with DENA operations are included in Other except for the Southeast operations, which are reflected in Commercial Power.

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Geographic Data

	U.S.	Canada	Other Foreign	Consolidated
			(in millions)	
2007				
Consolidated revenues(a)	$ 1,393	$ 3,349	$	$ 4,742
Consolidated long-lived assets	7,015	12,447		19,462
2006				
Consolidated revenues(a)	1,381	3,141	10	4,532
Consolidated long-lived assets	6,519	10,525		17,044
2005				
Consolidated revenues(a)	6,706	2,710	38	9,454

(a) Excludes revenues associated with businesses included in discontinued operations.

5. Regulatory Matters

Regulatory Assets and Liabilities. Spectra Energy s regulated operations are subject to SFAS No. 71. Accordingly, Spectra Energy records assets and liabilities that result from the regulated ratemaking process that would not be recorded under GAAP for non-regulated entities. See Note 1 for further discussion.

Regulatory Assets and Liabilities:

	December 31, 2007	2006	Recovery/Refund Period Ends
	(in millions)		
Regulatory Assets(a)			
Net regulatory asset related to income taxes(b)	$ 809	$ 848	(c)
Project costs(d)	45	37	2024
Hedge costs and other deferrals(d)	1	31	2008
Vacation accrual(d)	11	17	2008
Deferred debt expense(e)	8	11	2011
Environmental clean-up costs(d)	6	6	2017
Other(d)	9	9	(f)
Total Regulatory Assets	$ 889	$ 959	
Regulatory Liabilities(a)			
Removal costs(e)(g)	$ 397	$ 329	(h)
Gas purchase costs(i)	100	166	2008
Pipeline rate credit(g)	35	36	2041
Storage and transportation liability(i)	7	15	2008
Earnings sharing liability(i)		12	2007
Other deferred tax credits(e)(g)		5	(f)
Other(g)	29	6	2010
Total Regulatory Liabilities	$ 568	$ 569	

(a) All regulatory assets and liabilities are excluded from rate base unless otherwise noted.
(b) All amounts are expected to be included in future rate filings.
(c) Recovery/refund is over the life of the associated asset or liability.
(d) Included in Regulatory Assets and Deferred Debits.
(e) Included in rate base.
(f) Recovery/Refund period currently unknown.
(g) Included in Regulatory and Other Deferred Credits and Other Liabilities.
(h) Liability is extinguished over the lives of the associated assets.
(i) Included in Other Current Liabilities.

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Rate Related Information.

Maritimes & Northeast Pipeline L.L.C. (M&N LLC). On May 15, 2006, the FERC issued an order approving a settlement agreement that provides for a rate increase over rates charged prior to January 1, 2005. In June 2006, the difference between the settlement rates and the interim rates, plus interest, was refunded to applicable shippers. There was no material effect to Spectra Energy s consolidated results of operations as a result of the refund.

Maritimes & Northeast Pipeline, L.P. (M&N LP). In 2006, M&N LP operated under an NEB-approved toll settlement that expired December 31, 2006. A toll settlement agreement for the 2007 fiscal year was approved by the NEB on December 14, 2006.

Algonquin Gas Transmission, LLC (Algonquin). In April 2005, Algonquin filed and the FERC accepted new negotiated rate agreements with the Algonquin customers that include a rate moratorium provision through December 2008.

Gulfstream Natural Gas System, L.L.C. (Gulfstream). In June 2007, the FERC issued an order approving Gulfstream s Phase III expansion project. That order also required Gulfstream to file a Cost and Revenue Study three years after the Phase III facilities go in service. The projected filing date would be the fall of 2011.

East Tennessee Natural Gas, LLC (East Tennessee). On November 1, 2005, East Tennessee placed into effect new rates approved by FERC as a result of a rate settlement with customers. The settlement agreement includes a five-year rate moratorium and certain operational changes.

Texas Eastern Transmission, L.P. (Texas Eastern). Texas Eastern continues to operate under rates approved by FERC in 1998 in an uncontested settlement between Texas Eastern and its customers.

Union Gas. Union Gas has rates that are approved by the OEB. Final 2008 rates, reflecting the incentive regulation settlement agreement accepted by the OEB on January 17, 2008, will be implemented beginning April 1, 2008, retroactive to January 1, 2008.

In November 2006, Union Gas received a decision from the OEB on the regulation of rates for gas storage services in Ontario. The OEB determined that it would not regulate the rates for storage services to customers outside Union Gas franchise area or the rates for new storage services to customers within its franchise area. Since the issuance of the decision, five parties were unsuccessful in their appeals to the OEB regarding the decision. In June 2007, four parties petitioned the Lieutenant Governor in Council (LGIC) of Ontario to direct the OEB to review and change the November 2006 decision. Submissions were made to the LGIC on these petitions from other parties, including Union Gas, and the petitioning parties filed responses in August 2007. The timing of a response from the LGIC, if any, cannot be determined. Union Gas continues to act in accordance with the OEB s forbearance decision.

Union Gas recorded regulatory assets of $148 million as of December 31, 2007 and $162 million as of December 31, 2006 related to deferred income tax liabilities. Under the current OEB-authorized rate structure, income tax costs are recovered in rates based on the current income tax payable and do not include accruals for deferred income tax. However, as income taxes become payable as a result of the reversal of timing differences that created the deferred income taxes, it is expected that rates will be adjusted to recover these taxes. Since most of these timing differences are related to property, plant and equipment costs, this recovery is expected to occur over the life of the assets.

Union Gas has recorded removal costs of $380 million as of December 31, 2007 and $312 million as of December 31, 2006. These regulatory liabilities represent collections from customers under approved rates for future removal activities that are expected to occur associated with the regulated facilities.

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In addition, Union Gas has recorded regulatory liabilities of $100 million as of December 31, 2007 and $166 million as of December 31, 2006, representing gas cost collections from customers under approved rates that exceeded the actual cost of gas for the associated periods. Union Gas files quarterly with the OEB to ensure that customers rates reflect future expected prices based on published forward-market prices. The difference between the approved and the actual cost of gas is deferred for future repayment to customers and is a component of quarterly gas commodity rates.

BC Pipeline and Field Services. The existing BC Pipeline settlement agreement reached with customers and approved by the NEB expired on December 31, 2007. On December 18, 2007, the NEB approved 2008 interim transportation tolls until such time as the final 2008 interim transportation tolls are approved. BC Pipeline is currently involved in negotiating a settlement with its shippers.

The BC Pipeline and Field Services businesses in Western Canada recorded regulatory assets of $558 million as of December 31, 2007 and $570 million as of December 31, 2006 related to deferred income tax liabilities. Under the current NEB-authorized rate structure, income tax costs are recovered in tolls based on the current income tax payable and do not include accruals for deferred income tax. However, as income taxes become payable as a result of the reversal of timing differences that created the deferred income taxes, it is expected that the transportation and field services tolls will be adjusted to recover these taxes. Since most of these timing differences are related to property, plant and equipment costs, this recovery is expected to occur over a 20 to 30 year period.

When evaluating the recoverability of the BC Pipelines and Field Services regulatory assets, management takes into consideration the NEB regulatory environment, natural gas reserve estimates for reserves located, or expected to be located, near these assets, the ability to remain competitive in the markets served, and projected demand growth estimates for the areas served by BC Pipeline and Field Services businesses. Based on current evaluation of these factors, management believes that recovery of these tax costs is probable over the periods described above.

Management believes that the effects of the above matters will not have a material adverse effect on Spectra Energy s future consolidated results of operations, financial position or cash flows.

6. Impairments

During 2005, Field Services recorded a charge of $120 million due to the reclassification of pre-tax unrealized losses from Accumulated Other Comprehensive Income into earnings as a result of the discontinuance of certain cash flow hedges entered into to hedge Field Services commodity price risk. See Note 20 for a discussion of the effects of the DCP Midstream disposition transaction on certain cash flow hedges.

7. Other Income and Expenses, net

The components are as follows:

	2007	2006	2005
		(in millions)	
Income (Expense)			
Interest income	$ 26	$ 32	$ 41
Foreign currency exchange losses	(2)		(4)
AFUDC allowance (equity component)	23	11	8
Realized and unrealized mark-to-market effect on discontinued hedges		(19)	(64)
Other(a)	6	91	87
Total	$ 53	$ 115	$ 68

(a) In 2006 and 2005, primarily represents management fees charged by Spectra Energy to an unconsolidated affiliate. See Note 13 for further discussion.

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8. Income Taxes

The following details the components of income tax expense:

	2007	2006	2005
		(in millions)	
Current income taxes			
Federal	$ 316	$ 270	$ 869
State	21	(35)	80
Foreign	32	129	42
Total current income taxes	369	364	991
Deferred income taxes			
Federal	(15)	83	(82)
State	4	(22)	(15)
Foreign	85	(30)	32
Total deferred income taxes	74	31	(65)
Income tax expense from continuing operations	443	395	926
Income tax expense from discontinued operations	7	61	104
Income tax benefit from cumulative effect of change in accounting principle			(1)
Total income tax expense	$ 450	$ 456	$ 1,029

Earnings from Continuing Operations before Income Taxes

	2007	2006	2005
		(in millions)	
Domestic	$ 926	$ 945	$ 2,031
Foreign	461	386	304
Total earnings from continuing operations before income taxes	$ 1,387	$ 1,331	$ 2,335

Reconciliation of Income Tax Expense at the U.S. Federal Statutory Tax Rate to the Actual Tax Expense from Continuing Operations

	2007	2006	2005
		(in millions)	
Income tax expense, computed at the statutory rate of 35%	$ 485	$ 466	$ 817
State income tax, net of federal income tax effect(a)	16	(37)	42
Tax differential on foreign earnings	(44)	(36)	(32)
Pass-through of income tax expense(b)		26	81
Impairment of Bolivian investment(c)		(25)	
U.S. tax on repatriation of foreign earnings			34
Domestic production activities deduction	(11)		
Other items, net	(3)	1	(16)

Total income tax expense from continuing operations	$ 443	$ 395	$ 926
Effective tax rate	31.9%	29.7%	39.7%

(a) In 2006, a state income tax benefit of approximately $30 million was recognized due to a reduction in the unitary state tax rate as a result of Duke Energy s merger with Cinergy.
(b) Prior to April 2006, the effective date of the tax sharing agreement with Duke Energy, tax expenses and benefits were passed through to Duke Energy.
(c) In 2006, a tax benefit was recognized for an impairment of an investment in Bolivia due to a change in tax status, which is included in continuing operations.

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Net Deferred Income Tax Liability Components

	December 31, 2007	2006
	(in millions)	
Deferred credits and other liabilities	$ 212	$ 133
Federal effects of uncertain tax benefits	16	
Other	16	17
Total deferred income tax assets	244	150
Valuation allowance	(15)	(13)
Net deferred income tax assets	229	137
Investments and other assets	(1,039)	(1,387)
Accelerated depreciation rates	(1,400)	(636)
Regulatory assets and deferred debits	(645)	(1,033)
Total deferred income tax liabilities	(3,084)	(3,056)
Total net deferred income tax liabilities	$ (2,855)	$ (2,919)

The above deferred tax amounts have been classified in the Consolidated Balance Sheets as follows:

	December 31, 2007	2006
	(in millions)	
Other current assets	$ 46	$ 96
Other investments and other assets		5
Other current liabilities	(18)	(40)
Deferred credits and other liabilities	(2,883)	(2,980)
Total net deferred income tax liabilities	$ (2,855)	$ (2,919)

At December 31, 2007, Spectra Energy had unused state net operating loss carryforwards of approximately $198 million that expire beginning in 2015. The tax benefits associated with the state net operating losses of approximately $12 million are expected to be fully recoverable within the applicable statutory expiration periods.

At December 31 2007, Spectra Energy had foreign net operating loss carryovers of approximately $38 million and foreign capital loss carryovers of approximately $109 million that expire at various times beginning in 2009. Spectra Energy has established a valuation allowance of $15 million at December 31, 2007 and $13 million at December 31, 2006 against its deferred tax asset related to the foreign capital loss carryovers.

Spectra Energy adopted the provisions of FIN 48 on January 1, 2007. As a result of the implementation of FIN 48, Spectra Energy recognized an increase of $26 million in the liability for uncertain tax benefits, which was accounted for as a cumulative effect decrease to the January 1, 2007 balance of retained earnings. As of the date of adoption and after the impact of recognizing the increase in the liability noted above, Spectra Energy s unrecognized tax benefits totaled $75 million. Of this, $59 million would reduce the annual effective income tax rate if recognized.

In conjunction with the adoption of FIN 48, Spectra Energy accrued $13 million for the payment of cumulative interest and penalties at January 1, 2007. Spectra Energy recorded a net increase of $6 million in cumulative interest and penalties during 2007.

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Reconciliation of Gross Unrecognized Income Tax Benefits

	(in millions)
Balance at January 1, 2007	$ 75
Increases related to prior year tax positions	3
Decreases related to prior year tax positions	(5)
Increases related to current year tax positions	16
Decreases related to settlements with taxing authorities	(2)
Reductions due to lapse of statute of limitations	(6)
Foreign currency translation	5
Balance at December 31, 2007	$ 86

Spectra Energy recorded a net increase of $11 million in gross uncertain tax benefits during 2007. Of this, $3 million increased income tax expense and the remainder was attributable to uncertain tax benefits associated with deferred tax liabilities and goodwill.

Prior to January 1, 2007, Spectra Energy was included in the consolidated federal income tax return and certain combined and unitary state tax returns of Duke Energy. In connection with the spin-off, Spectra Energy indemnified Duke Energy for Spectra Energy s share of taxes on such returns. Accordingly, obligations of $42 million for uncertain federal and state income tax positions for periods in which Spectra Energy was included in a Duke Energy consolidated, combined or unitary filing have been recorded as guarantee obligations within Regulatory and Other Deferred Credits and Other Liabilities on the Consolidated Balance Sheet as of December 31, 2007. Spectra Energy has no liability to Duke Energy for federal income tax liabilities prior to 1999 and for state income tax liabilities prior to 1997 as those tax years have been closed.

Spectra Energy also files numerous returns in Canada where it is directly liable to the tax jurisdictions for tax assessments. Spectra Energy is no longer open to Canadian tax issues prior to 2001 since those tax years have been closed. The Canadian tax authorities are currently performing audit examinations of certain Canadian income tax returns for tax years ranging from 2002 through 2004. To date, there are no proposed adjustments that will have a material effect on Spectra Energy s consolidated results of operations or financial position.

Although uncertain, Spectra Energy believes it is reasonably possible that prior to December 31, 2008 the total amount of unrecognized tax benefits could decrease by approximately $17 million. The anticipated changes in unrecognized tax benefits relate to anticipated audit settlements focused primarily on classification of certain tax attributes, transfer pricing and expiration of statue of limitations.

Cumulative undistributed earnings on Spectra Energy s foreign subsidiaries at December 31, 2007 totaled $30 million for which Spectra Energy has not provided U.S. deferred income taxes and foreign withholding taxes since Spectra Energy intends to permanently reinvest such earnings in its foreign operations. Unrecognized U.S. deferred income taxes and foreign withholding taxes on the undistributed earnings are not expected to be material.

9. Discontinued Operations

In anticipation of the spin-off from Duke Energy, Spectra Capital implemented an internal reorganization in December 2006 in which the operations and assets of Spectra Capital that were not associated with the natural gas businesses were contributed by Spectra Capital to Duke Energy or its subsidiaries. Operations transferred included International Energy, Spectra Capital s effective 50% interest in Crescent and certain operations within Other, primarily Duke Energy Trading and Marketing, LLC, DukeNet Communications, LLC, Duke Energy Merchants, LLC and Spectra Capital s 50% interest in Duke/Fluor Daniel. Approximately $5.1 billion of assets, $1.9 billion of liabilities (which includes approximately $0.9 billion of debt), $0.2 billion of minority interest and $3.0 billion of member s equity were transferred from Spectra Capital to Duke Energy in December 2006. In April 2006, Spectra

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Capital transferred its ownership interest in DENA s Midwestern generation assets to a Duke Energy subsidiary. No gain or loss was recognized on the transfer of operations to Duke Energy as the transfers were among entities under common control. In addition, in 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. Spectra Energy does not anticipate significant continuing involvement in any of the businesses transferred to Duke Energy or sold to third parties. Therefore, the results of operations for 2006 and 2005 for these operations have been reflected as discontinued operations in the accompanying Consolidated Statements of Operations. Information presented for 2006 and 2005 in the Consolidated Statements of Cash Flows does not include any reclassifications or adjustments to amounts historically reported for these transferred businesses.

The following table summarizes the results classified as Income (Loss) from Discontinued Operations, Net of Tax, in the accompanying Consolidated Statements of Operations.

	Operating Revenues	Pre-tax Earnings (Loss)	Income Tax Expense (Benefit)	Income (Loss) From Discontinued Operations, Net of Tax
		(in millions)		
2007				
Other	$ 1	$ 20	$ 7	$ 13
Total consolidated	$ 1	$ 20	$ 7	$ 13
2006				
Commercial Power	$ 15	$ (16)	$ (2)	$ (14)
International Energy	961	64	54	10
Crescent	221	518	206	312
Other(a)	788	(197)	(197)	
Total consolidated	$ 1,985	$ 369	$ 61	$ 308
2005				
Field Services	$ 4	$	$	$
Commercial Power	113	(78)	16	(94)
International Energy	745	275	110	165
Crescent	497	304	100	204
Other(a)	2,813	(1,128)	(122)	(1,006)
Total consolidated	$ 4,172	$ (627)	$ 104	$ (731)

(a) Other includes the results for DENA s discontinued operations, excluding the operations of the Midwest and Southeast plants.

The following significant transactions, the effects of which are included in Income (Loss) From Discontinued Operations, Net of Tax on the Consolidated Statements of Income, occurred during 2007, 2006 and 2005.

2007

In 2007, $18 million of income ($11 million, net of tax), was recorded related to settlement proceeds of the Sonatrach/Sonatrading Amsterdam B.V. (Sonatrading) 2001 arbitration proceeding. See Note 18 for further discussion.

2006

Acquisitions. During 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). These acquisitions increased

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International Energy s ownership in Aguaytia to 66% and resulted in Spectra 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.

Also in 2006, Spectra 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 that were sold. See below for further discussion.

Dispositions. Significant sales of other assets and equity investments during 2006 were as follows:

Crescent. In 2006, a wholly owned subsidiary of Spectra 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 Spectra 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 Spectra Energy. Immediately following the debt transaction, the MS Members collectively acquired a 49% membership interest in the Crescent JV from Spectra 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. In conjunction with the Crescent JV transaction, Spectra Energy recognized a pre-tax gain on the sale of approximately $250 million in 2006. As a result of the Crescent transaction, Spectra Energy no longer controlled the Crescent JV and in September 2006 deconsolidated its investment in Crescent and accounted for its investment in the Crescent JV utilizing the equity method of accounting. 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.

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. Sales primarily consisted of two office buildings for a pre-tax gain of $81 million and land for a pre-tax gain of $52 million, as well as several other large land tract sales.

Other. As discussed above, during 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. Approximately $700 million was incurred from the announcement date through December 31, 2006, of which approximately $230 million was incurred during 2006. In January 2006, Spectra Energy signed an agreement to sell DENA s entire fleet of power generation assets outside the Midwest. This transaction closed in May 2006. Total proceeds from the sale were approximately $1.6 billion. As of December 31, 2006, the exit activities of DENA were substantially complete. See below for further discussion. In 2006, Spectra Energy recognized a $51 million pre-tax gain on the sale of available-for-sale securities that were classified as assets-held-for-sale at December 31, 2005, primarily related to DENA.

Impairments. In 2006, International Energy recorded a $50 million pre-tax 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 were generated from the gas compression services

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agreement with the Mexican national oil company (PEMEX). It was determined that there was a limited future need for Campeche s gas compression services. Management of International Energy determined that it was probable that the Campeche investment would ultimately be sold or the gas compression services agreement would 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 consisted of a $17 million impairment of the carrying value of the equity method investment and a $33 million reserve against notes receivable from Campeche.

In December 2006, Spectra 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 (subsequent to the December 2006 transfer of International Energy to Duke Energy), and resulted in the sale of International Energy s 50% ownership interest in two hydroelectric power plants near Cochabamba, Bolivia for $20 million. Based on the agreed upon selling price of the assets, in 2006 Spectra Energy recorded pre-tax impairment charges of $28 million. The impairment charges reduced the carrying value of the assets to the estimated selling price pursuant to the aforementioned agreement.

In the first quarter of 2006, a pre-tax allowance of $19 million ($12 million after tax) was recorded against a receivable due from the 2003 purchaser of International Energy s European operations. As a result of a settlement, a pre-tax write-up of the receivable of $9 million ($5 million after tax) was recorded in the second quarter of 2006 as a reduction in the valuation allowance. International Energy received the settlement proceeds in July 2006.

2005

Dispositions. Significant sales of other assets and equity investments during 2005 are detailed as follows:

Crescent. Crescent s commercial and multi-family real estate sales resulted in $372 million of proceeds and $197 million of net pre-tax gains in 2005. Sales included a large land sale in Lancaster County, South Carolina that resulted in $42 million of pre-tax gains, and several other 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.

Other. In connection with the exit plan of DENA previously discussed, Spectra Energy recognized pre-tax losses of approximately $1.1 billion in 2005, 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 were expected to be sold to their estimated fair value less cost to sell. Fair value of the assets that were 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 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

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2004, certain commodity contracts related to DENA Midwestern power generation facilities, and contracts related to DENA energy marketing and management activities. Excluded from the contracts sold to Barclays are commodity contracts associated with the near-term value of DENA West and Northeastern generation assets and with remaining gas transportation and structured power contracts. Approximately $470 million was incurred from the announcement date through December 31, 2005.

Among other things, the agreement provided 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 Spectra Energy with cash equal to the net cash collateral posted by DENA under the contracts of approximately $540 million.

In 2005, Spectra Energy s Grays Harbor facility was sold to an affiliate of Invenergy LLC, resulting in a pre-tax gain of $21 million. Also in 2005, Spectra Energy completed the sale of Spectra Energy s 75% interest in Bayside Power L.P. (Bayside).

Impairments. *International Energy.* A $20 million other than temporary impairment in value of the Campeche investment was recognized in 2005 to write down the investment to its estimated fair value.

Crescent. In 2005, Crescent recognized pre-tax impairment charges of approximately $16 million related to a residential community. 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.

10. Earnings per Common Share

Basic earnings per common share (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 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 and phantom stock awards, were exercised, settled or converted into common stock.

The following table presents Spectra Energy s basic and diluted EPS calculations.

	2007 (in millions, except per-share amounts)
Income from continuing operations	$ 944
Income from discontinued operations, net of tax	13
Net Income	$ 957
Weighted average shares	
Basic	632
Diluted	635
Basic and diluted earnings per common share	
Continuing operations	$ 1.49
Discontinued operations, net of tax	0.02
Total basic and diluted earnings per common share	$ 1.51

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Weighted-average shares used to calculate diluted EPS includes the effect of certain options and restricted stock awards. Certain other options and stock awards related to approximately nine million shares for 2007 were not included in the calculation of diluted EPS because either the option exercise prices were greater than the average market price of the common shares during this period or performance measures related to the awards had not yet been met.

Weighted-average shares outstanding and EPS data for 2006 and 2005 are not presented since Spectra Capital, the predecessor entity of Spectra Energy for financial reporting purposes, was a wholly owned subsidiary of Duke Energy during 2006 and 2005. As discussed in Note 1, approximately 631 million shares of Spectra Energy common stock were issued to Duke Energy shareholders on January 2, 2007 in connection with the spin-off.

11. Marketable Securities

At December 31, 2007, Spectra Energy had no short-term and $244 million of long-term investments. At December 31, 2006, there were no outstanding short-term or long-term investments.

Short-term investments. During 2006, Spectra Energy purchased $9,132 million and received proceeds on sale of $9,653 million of short-term investments. During 2005, Spectra Energy purchased $30,115 million and received proceeds on sale of $29,892 million of short-term investments.

Purchases and sales of available-for-sale securities are presented on a gross basis within Cash Flows from Investing Activities in the accompanying Consolidated Statements of Cash Flows.

During 2006, the U.S. Transmission business segment received shares of stock as consideration for settlement of a customer s transportation contracts. The market value of the equity securities, determined by quoted market prices on the date of receipt, of $28 million is reflected in Gains on Sales of Other Assets and Other, Net in the 2006 Consolidated Statement of Operations. Also during 2006, these securities were sold and an additional gain of $1 million was recognized in Other Income and Expenses, Net in the Consolidated Statements of Operations.

Other Long-term investments. During 2007, Spectra Energy invested a portion of the proceeds from Spectra Partners IPO in financial instruments, including money market or debt securities that frequently have stated maturities of 20 years or more. These investments, which totaled $155 million as of December 31, 2007, are pledged as collateral against Spectra Partners term loan and are classified as Other Investments on the Consolidated Balance Sheet at December 31, 2007. During 2007, Spectra Energy purchased $1,439 million and received proceeds on sale of $1,284 million of these investments.

On January 2, 2007, Duke Energy distributed to Spectra Energy certain corporate assets and liabilities, including $96 million of marketable securities held in a grantor trust account associated with captive insurance losses of approximately the same amount transferred to Spectra Energy. These securities, which are generally composed of short-term debt instruments, are classified as long-term since they are restricted for insurance reserves. During 2007, Spectra Energy purchased $93 million and received proceeds on sales of $121 million of other long-term investments within the captive insurance portfolio.

On April 1, 2006, Spectra Energy transferred the operations of Bison, a captive insurance entity, to Duke Energy. Prior to the transfer of Bison, Spectra Energy invested in debt and equity securities that were held in the captive insurance investment portfolio. Similar to the 2007 captive insurance positions, these investments were classified as long-term. During 2006, Spectra Energy purchased $158 million and received proceeds on sales of $122 million on other long-term investments within the captive insurance portfolio. During 2005, Spectra Energy purchased $803 million and received proceeds on sales of $814 million on other long-term investments within the captive insurance portfolio.

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Purchases and proceeds on sales of the long-term investments discussed above are classified within Cash Flows from Investing Activities on the Consolidated Statements of Cash Flows.

At December 31, 2007, there were no short-term investment balances, and at December 31, 2006, there were no short-term or long-term investments outstanding. The estimated fair values of long-term investments at December 31, 2007 classified as available-for-sale are as follows:

	December 31, 2007		
	Gross Unrealized Holding Gains	Gross Unrealized Holding Losses	Estimated Fair Value
		(in millions)	
Corporate debt securities	$	$	$ 125
Other			47
Total long-term investments	$	$	$ 172

The average contractual maturity of the above securities was either less than one year at December 31, 2007 or the security had been sold as of the date of this report.

12. Goodwill

The following tables show the components and activity within goodwill for the years ended December 31, 2007 and 2006, based on the SFAS No. 142 reporting unit determination.

	December 31, 2006	Increases(a)	December 31, 2007
		(in millions)	
U.S. Transmission	$ 2,098	$ 236	$ 2,334
Distribution	762	112	874
Western Canada Transmission & Processing	647	93	740
Total consolidated	$ 3,507	$ 441	$ 3,948

	December 31, 2005	Transfer to Duke Energy(b)	Other Increases (Decreases)(a)	December 31, 2006
		(in millions)		
U.S. Transmission(c)	$ 2,101	$	$ (3)	$ 2,098
Distribution	763		(1)	762
Western Canada Transmission & Processing	648		(1)	647
International Energy	256	(267)	11	
Crescent(d)	7		(7)	
Total consolidated	$ 3,775	$ (267)	$ (1)	$ 3,507

(a) Except as noted in (c) and (d), activity consists primarily of foreign currency translation.
(b) Represents Spectra Energy s December 2006 transfer of the operations of International Energy to Duke Energy. See Note 9.
(c) During 2006, Spectra Energy recorded a $16 million decrease in goodwill as a result of a deferred tax purchase price adjustment related to a prior period acquisition.
(d) Reduction in goodwill at December 31, 2006 reflects the deconsolidation of Crescent in September 2006. See Note 9.

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The following goodwill amounts originating from the acquisition of Westcoast Energy, Inc. (Westcoast) in 2002 are included in Other within the segment data presented in Note 4:

	December 31,	
	2007	2006
	(in millions)	
U.S. Transmission	$ 1,874	$ 1,638
Distribution	871	762
Western Canada Transmission & Processing	725	634

Spectra Energy completed its annual goodwill impairment test as of August 31, 2007 and no impairments were identified. Spectra Energy primarily uses a discounted cash flow analysis to determine fair value for each reporting unit. Key assumptions in the determination of fair value include the use of an appropriate discount rate and estimated future cash flows. In estimating cash flows, Spectra Energy incorporates expected long-term growth rates in key markets served by Spectra Energy s operations, regulatory stability, the ability to renew contracts, commodity prices (where appropriate), and foreign currency exchange rates, as well as other factors that affect its revenue, expense and capital expenditure projections.

The long-term growth rates and projected cash flows of the gathering and processing activities in Western Canada are sensitive to assumptions around the prospects for natural gas exploration and drilling in the areas of British Columbia and Alberta that are in close proximity to Spectra Energy s Western Canada assets (primarily in the western extent of the Western Canadian Sedimentary Basin). Although drilling slowed in 2006 and 2007 in certain of these areas (primarily in Northeastern British Columbia), management believes that low-to-moderate growth in Spectra Energy s operations is reasonable over the long-term. If this growth and expansion does not materialize in periods after 2010, the BC Field Services reporting unit could experience a decline in overall unit value, which could affect the ability to support the goodwill allocated to this unit.

13. Investments in and Loans to Unconsolidated Affiliates and Related Party Transactions

Investments in domestic and international affiliates for which Spectra Energy is not the primary beneficiary, but over which it has significant influence, are accounted for using the equity method. Spectra Energy received dividends from its equity investments of $656 million in 2007, $859 million in 2006 and $856 million in 2005.

As of December 31, 2007 and 2006, the carrying amount of investments in affiliates approximated the amount of underlying equity in net assets. Cumulative undistributed earnings of unconsolidated affiliates totaled $20 million at December 31, 2007 and $11 million at December 31, 2006.

U.S. Transmission. As of December 31, 2007, investments primarily include 50% interests in Gulfstream and Southeast Supply Header, LLC (SESH). Gulfstream is an interstate natural gas pipeline that extends from Mississippi and Alabama across the Gulf of Mexico to Florida. SESH is an interstate natural gas pipeline currently in development that will extend from Northeast Louisiana to Mobile County, Alabama where it will connect to the Gulfstream System. SESH is anticipated to be in service in the summer of 2008. Although Spectra Energy owns a significant portion of Gulfstream and SESH, they are not consolidated as Spectra Energy does not hold a majority of voting control or have the ability to exercise control over them.

In the third quarter of 2007, Spectra Energy and CenterPoint Energy Gas Transmission Company entered into a loan agreement with SESH whereby each member agreed to loan funds to SESH, as needed and on a pro rata basis, in connection with the construction of SESH pipeline facilities. The loans bear interest based on LIBOR and are payable the earlier of December 31, 2009 or when SESH obtains permanent construction financing. The loan receivable from SESH totaled $146 million at December 31, 2007.

Field Services. Spectra Energy s most significant investment in unconsolidated affiliates is the 50% interest in DCP Midstream. DCP Midstream is a limited liability company which is a pass-through entity for U.S.

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income tax purposes. DCP Midstream also owns corporations who file their own respective federal, foreign and state income tax returns. Income tax expense related to these corporations is included in the income tax expense of DCP Midstream. Therefore, DCP Midstream s net income does not include income taxes for earnings which are passed through to the members based upon their ownership percentage. Spectra Energy recognizes the tax effects of its share of DCP Midstream s pass-through earnings in Income Tax Expense from Continuing Operations in the accompanying Consolidated Statements of Operations.

In July 2005, Spectra Energy completed the transfer of a 19.7% interest in DCP Midstream to ConocoPhillips. As a result of the DCP Midstream disposition transaction, Spectra Energy deconsolidated its investment in DCP Midstream which has subsequently been accounted for as an investment utilizing the equity method of accounting. See Note 3 for further discussion of the DCP Midstream disposition transactions and also the sales of TEPPCO GP by DCP Midstream and the sale of Spectra Energy s interest in TEPPCO GP. For the three months ended March 31, 2005, TEPPCO LP had operating revenues of $1,524 million, operating expenses of $1,463 million, operating income of $61 million, income from continuing operations of $46 million and net income of $47 million.

Investments in and Loans to Unconsolidated Affiliates

	December 31, 2007			December 31, 2006		
	Domestic	International	Total	Domestic	International	Total
			(in millions)			
U.S. Transmission	$ 747	$	$ 747	$ 434	$	$ 434
Western Canada Transmission & Processing		19	19		18	18
Field Services	1,014		1,014	1,166		1,166
Total	$ 1,761	$ 19	$ 1,780	$ 1,600	$ 18	$ 1,618

Equity in Earnings of Unconsolidated Affiliates(a)

	2007			2006			2005		
	Domestic	International	Total	Domestic	International	Total	Domestic	International	Total
					(in millions)				
U.S.Transmission	$ 62	$	$ 62	$ 33	$	$ 33	$ 37	$	$ 37
Western Canada Transmission & Processing		2	2		2	2		5	5
Field Services(b)	532		532	574		574	308		308
Other							5		5
Total	$ 594	$ 2	$ 596	$ 607	$ 2	$ 609	$ 350	$ 5	$ 355

(a) Excludes amounts in discontinued operations, which primarily represent equity earnings of investments within the following: International Energy, Crescent and the equity investments within Other, which were transferred by Spectra Energy to Duke Energy in December 2006.
(b) Includes Spectra Energy s 50% equity in earnings of DCP Midstream subsequent to deconsolidation on July 1, 2005.

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Summarized Combined Financial Information of Unconsolidated Affiliates

	2007			2006			2005		
	DCP Midstream	Other	Total	DCP Midstream	Other (a)	Total	DCP Midstream (b)	Other (a)	Total
					(in millions)				
Statement of Operations(a)									
Operating revenues	$ 13,154	$ 272	$ 13,426	$ 12,335	$ 1,251	$ 13,586	$ 7,463	$ 1,336	$ 8,799
Operating expenses	11,959	117	12,076	11,063	792	11,855	6,814	836	7,650
Operating income	1,195	155	1,350	1,272	459	1,731	649	500	1,149
Net income	1,074	124	1,198	1,135	430	1,565	584	492	1,076

(a) Other includes amounts of unconsolidated affiliates of the International Energy and Crescent segments which were transferred to Duke Energy in December 2006 and presented as discontinued operations in 2006 and 2005 in the Consolidated Statements of Operations. See Note 9 for further discussion of discontinued operations.

(b) Represents data for the six-month period ended December 31, 2005.

	December 31, 2007			December 31, 2006		
	DCP Midstream	Other	Total	DCP Midstream	Other	Total
			(in millions)			
Balance Sheet						
Current assets	$ 2,248	$ 182	$ 2,430	$ 2,129	$ 88	$ 2,217
Non-current assets	5,757	2,383	8,140	4,767	1,725	6,492
Current liabilities	(2,460)	(86)	(2,546)	(2,177)	(49)	(2,226)
Non-current liabilities	(3,582)	(1,249)	(4,831)	(2,462)	(861)	(3,323)
Net Assets	$ 1,963	$ 1,230	$ 3,193	$ 2,257	$ 903	$ 3,160

Related Party Transactions

DCP Midstream. Spectra Energy had the following transactions with DCP Midstream and its affiliates during 2007, 2006 and the period July 1, 2005 through December 31, 2005: Sales of Natural Gas and Natural Gas Liquids of $9 million in 2007 and $12 million in both 2006 and the 2005 period, and Natural Gas and Petroleum Products Purchased of $2 million in 2007. In addition, $14 million of product purchases in 2006 and $65 million of product purchases in 2005 are included in Income (Loss) From Discontinued Operations, Net of Tax.

Spectra Energy had receivables from DCP Midstream and its affiliates of $64 million at December 31, 2007 and $71 million at December 31, 2006. Total distributions received from DCP Midstream were $618 million in 2007, $725 million in 2006 and $360 million in the 2005 period. Of these distributions, $532 million in 2007, $573 million in 2006 and $287 million in the 2005 period were recorded within Cash Flows from Operating Activities, and $86 million in 2007, $152 million in 2006 and $73 million in the 2005 period were recorded within Cash Flows from Investing Activities.

In 2005, DCP Midstream formed DCP Midstream Partners, LP (DCP Partners), a master limited partnership. DCP Partners completed an IPO transaction in December 2005 that resulted in net proceeds of $210 million. Throughout 2006 and 2007, there were a series of transactions including equity issuances resulting in net proceeds of $230 million and asset drop-downs from DCP Midstream into DCP Partners. As a result, at December 31, 2007, DCP Midstream has a 35.4% ownership interest in DCP Partners, consisting of a 33.9% limited partner ownership interest and a 1.5% general partner ownership interest. DCP Midstream s ownership interest in the general partner of DCP Partners is 100%. The gains on the IPO and equity issuances have been deferred by DCP Midstream until DCP Midstream converts the subordinated units in DCP Partners to common units, which will occur no earlier than December 31, 2008.

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DCP Midstream previously sold a portion of its residue gas and NGLs to, purchased raw natural gas and other petroleum products from, and provided gathering and transportation services to unconsolidated affiliates (primarily TEPPCO GP, which was sold in February 2005). Total revenues from these affiliates were $98 million, purchases were $77 million and operating expenses were $1 million for the six months ended June 30, 2005.

Duke Energy. Spectra Energy and Duke Energy and its affiliates are no longer considered related parties effective with the spin-off of Spectra Energy from Duke Energy on January 2, 2007.

Spectra Energy recorded income of $82 million in 2006 and $68 million in 2005 related to management fees charged to Duke Power Company (Duke Power), an unconsolidated affiliate of Spectra Energy. These amounts are recorded in Other Income and Expenses, Net on the Consolidated Statements of Operations. Additionally, Spectra Energy recognized recoveries of expenses of $777 million in 2006 and $466 million in 2005. These amounts represent recoveries of direct and allocated corporate governance and shared service costs charged to unconsolidated affiliates and are reflected as an offset within Operating, Maintenance and Other Expenses, and Depreciation and Amortization. Also included in Operating, Maintenance and Other Expenses in 2006 is $23 million of allocated costs charged to Spectra Energy by an affiliate of Cinergy. An additional $6 million of such costs included in Income (Loss) From Discontinued Operations, Net of Tax.

Also included in Operating, Maintenance and Other Expenses in 2006 is $22 million related primarily to insurance premiums paid to Bison subsequent to the transfer of Bison to Duke Energy in April 2006.

During 2006, Spectra Energy advanced $89 million to Duke Energy and also forgave advances to Duke Energy of $602 million. The advance is presented as Distributions and Advances to Parent within Cash Flows from Financing Activities in the Consolidated Statements of Cash Flows. The advances forgiven are considered non-cash financing activity.

During 2006, Spectra Energy distributed $2,361 million to Duke Energy. The distribution was principally obtained from the proceeds received on Spectra Energy s sale of 50% of Crescent as discussed further in Note 9. During 2005, Spectra Energy distributed $2,100 million to Duke Energy. The distribution was principally obtained from Spectra Energy s portion of the cash proceeds realized from the sale by DCP Midstream of TEPPCO GP and Spectra Energy s sale of its limited partner interest in TEPPCO noted above.

See Notes 1 and 9 for discussion of direct and indirect transfers of certain business from Spectra Energy to Duke Energy and Duke Energy Ohio during 2006.

During 2005, Duke Energy forgave advances totaling $761 million and Spectra Energy classified the $761 million as an addition to Member s Equity. These transactions were considered non-cash financing activity. Also during 2005, Spectra Energy received capital contributions of $269 million from Duke Energy, which Spectra Energy classified as an addition to Member s Equity. In addition, Spectra Energy advanced $242 million to Duke Energy in 2005.

Other miscellaneous balances due to or from Duke Energy or other affiliates included $15 million in Receivables, $27 million in Investments and Other Assets, and $18 million in Other Current Liabilities in the Consolidated Balance Sheet as of December 31, 2006.

Other. U.S. Transmission has a 50% ownership in three pipeline companies, Gulfstream, (an operating pipeline), Islander East, LLC and SESH (two development stage pipelines). U.S. Transmission also has a 49.5% ownership in Steckman Ridge, LP (Steckman), a development stage pipeline. Western Canada Transmission & Processing has 50% ownership in a power plant, McMahon Cogeneration Plant, a cogeneration natural gas fired facility. Spectra Energy provides certain administrative and other services to the pipeline companies and the power plant. Spectra Energy recorded recoveries of costs from these affiliates of $78 million in 2007, $19 million in 2006 and $12 million in 2005. Outstanding receivables from these affiliates totaled $8 million at December 31, 2007 and $5 million at December 31, 2006.

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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 $620 million was distributed to its partners based upon their ownership percentage ($310 million was received by U.S. Transmission and is included in Distributions From Unconsolidated Affiliates within Cash Flows from Investing Activities).

International Energy loaned money to Campeche, a 50%-owned affiliate, to assist in the costs to build. International Energy received principal and interest payments of approximately $11 million and $5 million from Campeche during 2006 and 2005, respectively.

An indirect wholly owned subsidiary of Spectra Energy contributed its membership interest in Crescent to a newly formed joint venture causing Spectra Energy to deconsolidate Crescent as of September 7, 2006. Spectra Energy s 50% share of the earnings of Crescent for the period from September 8, 2006 through December 31, 2006 was $15 million. As discussed in Note 1, in December 2006 Spectra Energy transferred its investment in Crescent to Duke Energy. As a result of this transfer, the results of operations, as well as the equity earnings for the period subsequent to September 7, 2006, are included in Income (Loss) From Discontinued Operations, Net of Tax. For the period September 8, 2006 through December 31, 2006, Crescent had operating revenues of $179 million, operating expenses of $152 million, operating income of $27 million and net income of $30 million.

See also Notes 3, 6, 16 and 19 for additional related party information.

14. Property, Plant and Equipment

	Estimated Useful Life (years)	December 31, 2007	2006
		(in millions)	
Plant			
Natural gas transmission	20 82	$ 10,056	$ 9,103
Natural gas distribution	27 60	2,337	1,939
Gathering and processing facilities(a)	25 40	2,914	2,376
Storage	15 122	1,066	882
Other buildings and improvements	16 50	94	76
Equipment(a)	3 40	381	319
Vehicles	2 20	99	86
Land		177	156
Construction in process		557	306
Other	3 82	473	396
Total property, plant and equipment		18,154	15,639
Total accumulated depreciation(b)		(3,854)	(3,245)
Total net property, plant and equipment		$ 14,300	$ 12,394

(a) Capital leases totaled $21 million at December 31, 2007 and $4 million at December 31, 2006.
(b) Includes no material accumulated amortization of capitalized leases.

15. Asset Retirement Obligations

Asset retirement obligations at Spectra Energy relate primarily to the retirement of certain gathering pipelines and processing facilities, obligations related to right-of-way agreements, and contractual leases for land use. However, Spectra Energy has determined that a significant portion of its assets have an indeterminate life, and thus the fair value of the retirement obligation is not reasonably estimable. These assets include on-shore and some off-shore pipelines, and certain processing plants and distribution facilities. A liability for these asset retirement obligations will be recorded when a fair value is determinable.

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In March 2005, the FASB issued FIN 47, which clarifies the accounting for conditional asset retirement obligations as used in SFAS No. 143. The provisions of FIN 47 were effective for Spectra Energy as of December 31, 2005, and resulted in a net-of-tax cumulative effect adjustment to earnings of $4 million.

Asset retirement obligations are adjusted each period for liabilities incurred or settled during the period, accretion expense and any revisions made to the estimated cash flows.

Reconciliation of Asset Retirement Obligation Liabilities

	2007	2006
	(in millions)	
Balance at beginning of year	$ 85	$ 29
Accretion expense	5	2
Revisions in estimated cash flows(a)	9	54
Foreign currency impact	13	
Balance at end of year(b)	$ 112	$ 85

(a) Estimate revised in 2006 primarily as a result of a detailed study conducted during 2006 by an industry expert on historical experience with abandonment.
(b) Amounts included in Regulatory and Other Deferred Credits and Other Liabilities in the Consolidated Balance Sheets.

16. Debt and Credit Facilities

Summary of Debt and Related Terms

	Weighted-Average Interest Rate	Year Due	December 31, 2007	December 31, 2006
			(in millions)	
Unsecured debt	7.1%	2008 2036	$ 7,707	$ 7,456
Secured debt	6.5%	2008 2019	965	807
Capital leases	6.7%	2008 2009	3	3
Commercial paper(a)	5.4%		715	349
Fair value hedge carrying value adjustment		2009 2018	15	13
Unamortized debt discount and premium, net			(7)	(3)
Total debt(b)			9,398	8,625
Current maturities of long-term debt			(338)	(550)
Short-term notes payable and commercial paper(c)			(715)	(349)
Total long-term debt			$ 8,345	$ 7,726

(a) The weighted-average days to maturity was 13 days as of December 31, 2007 and 22 days as of December 31, 2006.
(b) As of December 31, 2007 and 2006, $4,144 million and $3,820 million of debt were denominated in Canadian dollars, respectively.
(c) Weighted-average rates on outstanding short-term notes payable and commercial paper was 5.4% as of December 31, 2007 and 5.5% as of December 31, 2006.

Secured Debt. Secured debt includes project financing for Maritimes & Northeast Pipeline, LLC, and Maritimes & Northeast Pipeline, LP (collectively, M&N Pipeline). Ownership interests in M&N Pipeline and certain of M&N Pipeline s accounts, revenues, business contracts and other assets are pledged as collateral. Secured debt also includes the term debt of Spectra Partners, which is collaterized by investment-grade securities.

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Floating Rate Debt. Unsecured debt, secured debt and other debt included approximately $1,276 million of floating-rate debt as of December 31, 2007 and $815 million as of December 31, 2006. The weighted average interest rate of borrowings outstanding that contained floating rates was 5.5% at December 31, 2007 and 5.4% at December 31, 2006.

Annual Maturities

	December 31, 2007 (in millions)
2008	$ 338
2009	918
2010	828
2011	306
2012	773
Thereafter	5,520
Total long-term debt(a)	$ 8,683

(a) Excludes short-term notes payable and commercial paper of $715 million.

Spectra 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.

Available Credit Facilities and Restrictive Debt Covenants. Spectra Capital entered into a new $1.5 billion credit facility in May 2007 that replaced two existing facilities that totaled $950 million. In July 2007, Union Gas replaced the existing $400 million Canadian 364-day credit facility with a $500 million Canadian five-year credit facility. Also in July 2007, in conjunction with Spectra Partners IPO discussed further in Note 2, Spectra Partners entered into a five-year $500 million facility that includes both term and revolving borrowing capacity. Obligations under the revolving portion of its credit facility are unsecured and the term borrowings are secured by qualifying investment grade securities in an amount equal to or greater than the outstanding principal amount of the term loan.

The issuance of commercial paper, letters of credit and other borrowings reduces the amount available under the available credit facilities.

Credit Facilities Summary

			Outstanding at December 31, 2007			
	Expiration Date	Credit Facilities Capacity	Commercial Paper	Term Loan	Revolving Credit	Letters of Credit	Total
				(in millions)			
Spectra Energy Capital, LLC	2012	$ 1,500(a)	$ 478	$	$	$ 16	$ 494
Westcoast Energy, Inc.	2011	200(b)					
Union Gas Limited	2012	501(c)	237				237
Spectra Energy Partners, LP	2012	500(d)		153	97		250
Total		$ 2,701	$ 715	$ 153	$ 97	$ 16	$ 981

(a) Credit facility contains a covenant requiring the debt-to-total capitalization ratio to not exceed 65%.

(b) 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%.

(c) Credit facility is denominated in Canadian dollars totaling 500 million Canadian dollars and contains a covenant that requires the debt-to-total capitalization ratio to not exceed 75% and a provision which requires Union Gas to repay all borrowings under the facility for

a period of two days during the second quarter of each year.

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(d) Contains a covenant requiring the borrower to collateralize the term loan with qualifying investment-grade securities in an amount equal to or greater than the outstanding principal amount of the loan. The terms of the credit facility allow for liquidation of collateral to fund capital expenditures or certain acquisitions provided that an equal amount of term loan is converted to a revolving loan.

Spectra 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, 2007, Spectra Energy was in compliance with those covenants. In addition, credit agreements allow for acceleration of payments or termination of the agreements due to nonpayment, or in some cases, due 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.

17. Preferred and Preference Stock

In connection with the Westcoast acquisition in 2002, Spectra Energy assumed 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, 2007 and 2006. 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.

18. Commitments and Contingencies

General Insurance

Spectra Energy carries, either directly or through its captive insurance companies, insurance coverages consistent with companies engaged in similar commercial operations with similar type properties. Spectra Energy s insurance program includes (1) commercial general and excess liability insurance for liabilities arising to third parties for bodily injury and property damage resulting from Spectra 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 Spectra Energy s by-laws and (5) property insurance covering the replacement value of real and personal property damage, including damages arising from machinery breakdowns, earthquake and flood damage, and extra expense. All coverages are subject to certain deductibles, terms and conditions common for companies with similar types of operations. The cost of Spectra Energy s general insurance coverage will continue to fluctuate reflecting changing conditions of the insurance markets.

Environmental

Spectra 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 Spectra Energy.

Remediation activities. Like others in the energy industry, Spectra Energy and its affiliates are responsible for environmental remediation at various contaminated sites. These include some properties that are part of ongoing Spectra Energy operations, sites formerly owned or used by Spectra 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 international, federal, state/provincial and local agencies, activities vary with site conditions and locations, remedial requirements, complexity and sharing of

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responsibility. If remediation activities involve statutory joint and several liability provisions, strict liability, or cost recovery or contribution actions, Spectra Energy or its affiliates could potentially be held responsible for contamination caused by other parties. In some instances, Spectra 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 operations. Management believes that completion or resolution of these matters will not have a material adverse effect on Spectra Energy s consolidated results of operations, financial position or cash flows.

Extended Environmental Activities, Accruals. Included in Regulatory and Other Deferred Credits and Other Liabilities on the Consolidated Balance Sheets were accruals related to extended environmental-related activities totaling $22 million at December 31, 2007 and $21 million at December 31, 2006. These accruals represent Spectra Energy s provisions for costs associated with remediation activities at some of its current and former sites, as well as other environmental contingent liabilities. Management believes that completion or resolution of these matters will have no material adverse effect on Spectra Energy s consolidated results of operations, financial position or cash flows.

Litigation

Sonatrach/Sonatrading Arbitration. In an arbitration proceeding that commenced in January 2001 in London, England, Duke Energy LNG Sales Inc., now Spectra Energy LNG Sales, Inc. (Spectra Energy LNG), claimed that Sonatrach, the Algerian state-owned energy company, together with its subsidiary, Sonatrading, breached their shipping obligations under a liquefied natural gas (LNG) purchase agreement and related transportation agreements (the LNG Agreements) relating to Spectra Energy LNG s purchase of LNG from Algeria and its transportation by LNG tanker to Lake Charles, Louisiana. Sonatrading and Sonatrach claimed that Spectra Energy LNG had repudiated the LNG Agreements by allegedly failing to diligently perform LNG marketing obligations. In 2003, the arbitration tribunal issued a Partial Award on liability issues and found that Sonatrach and Sonatrading breached their obligations to provide shipping. The tribunal also found that Spectra Energy LNG breached the LNG Purchase Agreement by failing to perform marketing obligations. The tribunal issued its award on damages on November 30, 2006. In the second quarter of 2007, the parties reached a settlement agreement on claims which accrued on or prior to May 24, 2002. Under the settlement agreement, Spectra Energy LNG received $18 million, which was recorded as $11 million in Income from Discontinued Operations, Net of Tax in the Consolidated Statements of Operations. The parties continue settlement discussions that address Spectra Energy LNG s claims for the period after May 24, 2002.

Duke Energy Retirement Cash Balance Plan. A class action lawsuit was filed in federal court in South Carolina against Duke Energy and the Duke Energy Retirement Cash Balance Plan. Various causes of action are alleged, including violations of the Employee Retirement Income Security Act of 1974 (ERISA) and the Age Discrimination in Employment Act. These allegations arise out of the conversion of the Duke Power Company Employees Retirement Plan into the Duke Power Company Retirement Cash Balance Plan. 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. Duke Energy filed its answer in March 2006. A motion to certify a class action was filed by the plaintiffs and Duke Energy filed its response in opposition to this motion. This class certification motion is pending before the federal court along with dispositive motions that have been filed. A hearing on the motions was held in December 2007, and the Court took the matters under advisement. 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. In connection with the spin-off from Duke Energy in January 2007, Spectra Energy has agreed to share with Duke Energy any liabilities or damages associated with this matter that relate to Spectra Energy employees that may be members of the plaintiff class. It is not possible to predict with certainty whether Spectra Energy will incur any liability or to estimate the damages, if any, that might be incurred in connection with this matter.

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Other Litigation and Legal Proceedings. Spectra Energy and its subsidiaries are involved in other legal, tax and regulatory proceedings in various forums arising in the ordinary course of business, including matters regarding contract, royalty, measurement and payment claims, some of which involve substantial monetary amounts. Spectra Energy has insurance coverage for certain of these losses should they be incurred. Management believes that the final disposition of these proceedings will not have a material adverse effect on Spectra Energy s consolidated results of operations, financial position or cash flows.

Spectra Energy has exposure to certain legal matters that are described herein. Spectra Energy had recorded reserves of $100 million as of December 31, 2006 related to certain litigation matters that were resolved and paid in January 2007, and had no material reserves as of December 31, 2007. These reserves represent management s best estimate of probable loss as defined by SFAS No. 5, Accounting for Contingencies.

Legal costs related to the defense of loss contingencies are expensed as incurred.

Other Commitments and Contingencies

Spectra Energy Islander East Pipeline Company, LLC (Spectra Islander), a wholly owned subsidiary, is a 50% equity partner and operator for the Islander East pipeline project which is owned by Islander East Pipeline Company, L.L.C. (Islander East), a proposed pipeline that would connect natural gas supplies to markets on Long Island, New York. This project has received FERC and other approvals but has been denied a Section 401 Water Quality Certificate by the State of Connecticut and is the subject of an appeal before the 2nd Circuit U.S. Court of Appeals. Oral arguments on the appeal were heard in April 2007. In August 2007, a Connecticut U.S. District Court determined that the Secretary of Commerce s 2004 decision to override the State s denial to issue a Coastal Zone Management Act approval was not supported by the record and remanded the matter back to the Secretary of Commerce. Islander East and the U.S. Office of Solicitor General (the Solicitor General) then filed appeals with the 2nd Circuit U.S. Court of Appeals to overturn the lower court s decision to remand and the State filed a motion to dismiss claiming the U.S. District Court s remand order was non-appealable. In January 2008, the 2nd Circuit granted the State s motion to dismiss and Islander East and the Solicitor General are evaluating various options including seeking the reconsideration of the 2nd Circuit s recent decision. Management continues to believe that there are sufficient factual and legal bases supporting Islander East s position that the State s denial of the certificate was improper and that the U.S. District Court s decision was in error. Management has deferred the project completion date from its previous plans to accommodate the resolution of the appeals. However, if the State s position is ultimately upheld, Islander East may be unable to proceed with the project as it is currently configured. As of December 31, 2007, Islander East had incurred and capitalized cumulative development costs of $67 million. Algonquin, a wholly owned subsidiary, also has a companion project, the AGT Islander East Lease Project. As of December 31, 2007 Algonquin had incurred and capitalized cumulative development costs of $20 million associated with the AGT Islander East Lease Project. Management expects the development and material costs incurred to date could be utilized by other capital projects of Spectra Energy or a deferred project of Islander East.

See also Note 19 for a discussion of guarantees and indemnifications.

Operating and Capital Lease Commitments

Spectra Energy leases assets in several areas of its operations. Consolidated rental expense for operating leases classified in Income From Continuing Operations was $45 million in 2007, $36 million in 2006 and $53 million in 2005, which is included in Operating, Maintenance and Other on the Consolidated Statements of Operations. Spectra Energy recorded pre-tax consolidated rental expense for operating leases classified in Income (Loss) From Discontinued Operations, Net of Tax of $37 million in 2006 and $27 million in 2005. Amortization of assets recorded under capital leases included in continuing operations was included in

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Depreciation and Amortization. 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, 2007:

	Operating Leases	Capital Leases
	(in millions)	
2008	$ 53	$ 2
2009	43	1
2010	31	
2011	27	
2012	23	
Thereafter	54	
Total future minimum lease payments	$ 231	$ 3

19. Guarantees and Indemnifications

Spectra Energy and certain of its subsidiaries have various financial guarantees and indemnifications which are issued in the normal course of business. As discussed below, these contracts include financial guarantees, stand-by letters of credit, debt guarantees, surety bonds and indemnifications. Spectra 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. To varying degrees, these guarantees involve elements of performance and credit risk, which are not included on the Consolidated Balance Sheets. The possibility of Spectra Energy 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.

Spectra 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. In connection with the spin-off of Spectra Energy to Duke Energy shareholders, certain guarantees that were previously issued by Spectra Energy were assigned to, or replaced by, Duke Energy in 2006. For any remaining guarantees of other Duke Energy obligations, Duke Energy has indemnified Spectra Energy against any losses incurred under these guarantee arrangements.

The maximum potential amount of future payments Spectra Energy could have been required to make under these performance guarantees as of December 31, 2007 was approximately $868 million, of which approximately $468 million has been indemnified by Duke Energy, as discussed above. Approximately $34 million of the performance guarantees expire in the years 2008 through 2010, with the remaining performance guarantees expiring after 2010 or having no contractual expiration. See also Note 8 for further discussion regarding income tax matters between Spectra Energy and Duke Energy.

Additionally, Spectra Energy has issued joint and several guarantees to some of the Duke/Fluor Daniel (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 could be required to make. 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, a wholly owned subsidiary, 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. Certain guarantees that were previously issued by Westcoast for obligations of entities that remained a part of Duke Energy are considered guarantees of third party performance; however, Duke Energy has indemnified Spectra Energy against any losses incurred under these guarantee arrangements.

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The maximum potential amount of future payments Westcoast could have been required to make under those performance guarantees of non-wholly owned entities and third-party entities as of December 31, 2007 was $115 million, of which $30 million has been indemnified by Duke Energy, as discussed above. Of the total Westcoast amount, $20 million relates to guarantees associated with the debt at Maritimes & Northeast Limited Partnership, a non-wholly owned consolidated entity. Guarantees related to Westcoast expire after 2009 or have no contractual expiration.

Spectra 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, Spectra 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 Spectra Energy could have been required to make under these letters of credit as of December 31, 2007 was $13 million.

Spectra 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. Spectra 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. Spectra 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, 2007, the amounts recorded for the guarantees and indemnifications, described above, including the indemnifications by Duke Energy to Spectra Energy, are not material, both individually and in the aggregate.

20. Risk Management and Hedging Activities, Credit Risk and Financial Instruments

Spectra Energy is exposed to the impact of market fluctuations in the prices of NGLs and natural gas marketed and purchased primarily as a result of the investment in DCP Midstream and ownership of the Empress operations in Canada. Exposure to interest rate risk exists as a result of the issuance of variable and fixed-rate debt and commercial paper. Spectra Energy is exposed to foreign currency risk from the Canadian operations. Spectra Energy employs established policies and procedures to manage its risks associated with these market fluctuations, which may include the use of forward physical transactions as well as other commodity derivatives, primarily within DCP Midstream, such as swaps and options.

Spectra Energy s Derivative Portfolio Carrying Value as of December 31, 2007

Asset/(Liability)	Maturity in 2008	Maturity in 2009	Maturity in 2010	Maturity in 2011 and Thereafter	Total Carrying Value
			(in millions)		
Hedging	$	$ 17	$	$ (2)	$ 15
Undesignated		2	(3)	14	13
Total	$	$ 19	$ (3)	$ 12	$ 28

The amounts in the table above represent the combination of amounts presented as assets (liabilities) for unrealized gains and losses on mark-to-market and hedging transactions on Spectra Energy s Consolidated Balance Sheet.

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As a result of the transfer of the 19.7% interest in DCP Midstream to ConocoPhillips and the third quarter 2005 deconsolidation of its investment in DCP Midstream, Spectra Energy discontinued hedge accounting for certain contracts held by Spectra 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 subsequent to deconsolidation, were retained as undesignated derivatives through their termination at the end of 2006. After the discontinuance of hedge accounting, these contracts were marked-to-market in the Consolidated Statements of Operations for the remainder of 2005 and through the termination date in 2006. As a result, $19 million and $314 million of realized and unrealized pre-tax losses related to these contracts were recognized in earnings by Spectra Energy in 2006 and 2005, respectively. The 2006 mark-to-market impacts have been classified in the accompanying Consolidated Statements of Operations as a component of Other Income and Expenses, Net. The 2005 mark-to-market impacts were classified 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 DCP Midstream were recognized as a component of Sales of Natural Gas and Natural Gas Liquids and $64 million of losses recognized subsequent to the deconsolidation of DCP Midstream were recognized as a component of Other Income and Expenses, Net. Cash settlements on these contracts since the deconsolidation of DCP Midstream on July 1, 2005 of $163 million in 2006 and $133 million in 2005 are classified as a component of Settlement of Net Investment Hedges and Other Investing Derivatives included in net cash used in investing activities in the accompanying Consolidated Statements of Cash Flows.

Commodity Cash Flow Hedges. Certain Spectra Energy subsidiaries are exposed to market fluctuations in the prices of natural gas and NGLs related to natural gas gathering, distribution, processing and marketing activities. Spectra Energy closely monitors the potential effects of commodity price changes and may choose to enter into contracts to protect margins for a portion of future sales and fuel expenses by using financial commodity instruments, such as swaps and options, as cash flow hedges for natural gas and NGL transactions, primarily within the operations of DCP Midstream.

The ineffective portion of commodity cash flow hedges from continuing operations resulted in a pre-tax gain of $4 million in 2006 and a pre-tax loss of $7 million in 2005, and is reported primarily in Other Revenues in the Consolidated Statements of Operations.

As of December 31, 2007, $1 million of pre-tax deferred net loss on derivative instruments related to commodity cash flow hedges were accumulated on the Consolidated Balance Sheets in a separate component of Member s 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 commodity markets, the corresponding value in AOCI will likely change prior to its reclassification into earnings.

Interest Rate (Fair Value or Cash Flow) Hedges. Changes in interest rates expose Spectra Energy to risk as a result of its issuance of variable and fixed-rate debt and commercial paper. Spectra 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. Spectra Energy also enters into financial derivative instruments, including, but not limited to, interest rate swaps and U.S. Treasury lock agreements to manage and mitigate interest rate risk exposure. Spectra Energy s fair value and cash flow interest rate hedge ineffectiveness were not material to its consolidated results of operations in 2007, 2006 and 2005.

Foreign Currency (Fair Value, Net Investment or Cash Flow) Hedges. Spectra Energy is exposed to foreign currency risk from investments and operations in international affiliate businesses. 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. Spectra Energy may also use foreign currency derivatives, where possible, to manage its risk related to foreign currency fluctuations. There were no foreign currency derivative transactions during 2007 and 2006, and a net gain of $1 million included in the cumulative translation adjustment for hedges of net investments in foreign operations during 2005. To monitor its currency exchange rate risks, Spectra Energy uses sensitivity analysis, which measures the effect of devaluation of foreign currencies.

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During 2005, Spectra Energy settled certain hedges which were documented and designated as net investment hedges of the investment in Westcoast on their scheduled maturity and paid $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 Spectra Energy s investment in Westcoast occurs.

Undesignated Derivative Contracts. Spectra Energy has certain gas supply and power sales contracts in the Western Canada operations that are accounted for as undesignated derivative contracts.

Credit Risk. Spectra Energy s principal customers for natural gas transportation, storage and gathering and processing services are industrial end-users, marketers, exploration and production companies, local distribution companies and utilities located throughout the U.S. and Canada. Spectra Energy has concentrations of receivables from natural gas utilities and their affiliates, industrial customers and marketers throughout these regions, as well as retail distribution customers in Canada. These concentrations of customers may affect Spectra Energy s overall credit risk in that risk factors can negatively affect the credit quality of the entire sector. Where exposed to credit risk, Spectra 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. Spectra Energy also obtains parental guarantees, cash or letters of credit from customers to provide credit support, where appropriate, based on its financial analysis of the customer and the regulatory or contractual terms and conditions applicable to each transaction.

Included in Other Current Liabilities and Regulatory and Other Deferred Credits and Other Liabilities are collateral liabilities of $81 million at December 31, 2007 and $70 million at December 31, 2006 which represent cash collateral posted by third parties to Spectra Energy.

Financial Instruments. The fair value of financial instruments, excluding derivatives included elsewhere in this Note and in Note 16, 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, 2007 and 2006, are not necessarily indicative of the amounts Spectra Energy could have realized in current markets.

Financial Instruments

	December 31,			
	2007		2006	
	Book Value	Approximate Fair Value	Book Value	Approximate Fair Value
	(in millions)			
Long-term debt(a)	$ 8,683	$ 9,461	$ 8,276	$ 9,182
Long-term SFAS 115 securities	172	172		
Other long-term assets	265	265	36	36

(a) Includes current maturities.

The fair value of cash and cash equivalents, short-term investments, accounts and notes receivable, accounts payable, notes 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.

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21. Stock-Based Compensation

Spectra Energy accounts for stock-based awards under the provisions of SFAS No. 123(R), Share-Based Payment, which established the 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.

Prior to the spin-off of Spectra Energy from Duke Energy, certain of Spectra Energy s employees participated in Duke Energy s stock-based compensation programs. Prior to the adoption of SFAS 123(R), Spectra Energy applied 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 prices for all Duke Energy options granted during these years under those plans were equal to the market value of the underlying common stock on the grant date, no compensation cost was allocated from Duke Energy.

Impact of Spin-off on Equity Compensation Awards of Employees

In anticipation of the spin-off, on December 19, 2006, Spectra Energy adopted the Spectra Energy Corp 2007 Long-Term Incentive Plan (the 2007 LTIP). The 2007 LTIP provides for the granting of stock options, restricted stock awards and units, unrestricted stock awards and units, and other equity-based awards, to employees and other key individuals who perform services for Spectra Energy. A maximum of 30 million shares of common stock may be awarded under the 2007 LTIP.

Options granted under the 2007 LTIP are issued with exercise prices equal to the fair market value of Spectra Energy common stock on the grant date, have ten year terms and vest immediately or over terms not to exceed five years. Compensation expense related to stock options is recognized over the requisite service period. The requisite service period for stock options is the same as the vesting period, with the exception of retirement eligible employees, who have shorter requisite service periods ending when the employees become retirement eligible.

Restricted, performance and phantom stock awards granted under the 2007 LTIP typically become 100% vested on the three-year anniversary of the grant date. The fair value of the awards granted is measured based on the fair market value of the shares on the date of grant, and the related compensation expense is recognized over the requisite service period which is the same as the vesting period.

At the time of the spin-off, Duke Energy converted stock options, restricted stock awards, performance awards and phantom stock awards (collectively, Stock-Based Awards) of Duke Energy common stock held by Duke Energy and Spectra Energy employees. One replacement Duke Energy Stock-Based Award and one-half Spectra Energy Stock-Based Award were distributed to each holder of Duke Energy Stock-Based Awards for each award held at the time of the spin-off. In the case of stock options, in accordance with the separation agreements, the option price conversion was based on the pre-distribution Duke Energy closing price of $19.14 relative to the Spectra Energy when-issued closing price of $28.62 on January 3, 2007. The revised awards therefore maintained both the pre-conversion aggregate intrinsic value of each award and the ratio of the exercise price per share to the fair market value per share. Substantially all converted Stock-Based Awards are subject to the terms and conditions applicable to the original Duke Energy stock options, restricted stock awards, performance awards and phantom stock awards. The Spectra Energy Stock-Based Awards resulting from the conversion are considered to have been issued under the 2007 LTIP.

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The conversion of Duke Energy stock awards to Spectra Energy stock awards constituted a modification of those stock awards under the provisions of SFAS No. 123(R). However, under the provisions of FASB Staff Position (FSP) No. 123(R)-5, since the modification was made to stock awards issued to employees for instruments that were originally issued as compensation and then modified, and that modification was 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 occurred as (a) there was no increase in fair value of the awards (the holders were made whole) and (b) all holders of the same class of equity instruments (for example, stock options) were treated in the same manner.

After the spin-off, Spectra Energy receives all cash proceeds related to the exercise of Spectra Energy stock options held by Duke Energy employees; however, Duke Energy will recognize all associated expense and resulting tax benefits relating to such stock options. Similarly, Spectra Energy will recognize all associated expense and tax benefits relating to Duke Energy awards held by Spectra Energy employees. Spectra Energy recognizes compensation expense, receives all cash proceeds and retains all tax benefits relating to Spectra Energy awards held by Spectra Energy employees.

Spectra Energy recorded pre-tax stock-based compensation expense included in continuing operations for 2007, 2006 and 2005 as follows, the components of which are further described below:

	2007	2006(a)	2005(a)
		(in millions)	
Stock Options	$ 10	$ 2	$
Stock Appreciation Rights(b)	(3)	2	1
Phantom Stock	7	7	5
Performance Awards	5	7	6
Total	$ 19	$ 18	$ 12

(a) Allocated from Duke Energy.
(b) Stock appreciation rights settled in cash must be marked to market with the increases/decreases resulting in a change to the measured compensation cost until exercise or expiration.

The tax benefit in income from continuing operations associated with the recorded expense was $7 million in 2007, $7 million in 2006 and $4 million in 2005. Excluded from amounts above are pre-tax stock-based compensation expense of $31 million in 2006 and $26 million in 2005 that are included in Income (Loss) From Discontinued Operations, Net of Tax on the Consolidated Statements of Operations. The tax benefits associated with the amounts that are included in Income (Loss) From Discontinued Operations, Net of Tax are $11 million in 2006 and $10 million in 2005. There were no material differences in income from continuing operations, income tax expense, net income or cash flows from the adoption of SFAS No. 123(R). In 2007, Spectra Energy recognized a tax benefit from stock-based compensation cost of approximately $20 million in additional paid in capital.

The following table shows what net income would have been for Spectra Energy if Duke Energy had applied the fair value recognition provisions of SFAS No. 123(R) to all stock-based compensation awards in 2005.

	2005
	(in millions)
Net income, as reported	$ 674
Add: stock-based compensation expense included in reported net income, net of related tax effects	24
Deduct: total stock-based compensation expense determined under fair value-based method for all awards, net of related tax effects	(26)

Pro forma net income, net of related tax effects	$ 672

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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, 2006(a)	13,466	$ 25	4.3	$ 75
Granted	2,200	26	9.2	
Exercised	(913)	19		
Forfeited or expired	(383)	31		
Outstanding at December 31, 2007	14,370	25	4.9	46
Exercisable at December 31, 2007	12,203	25	4.1	46
Options Expected to Vest	2,134	26	9.2	

(a) Represents the Spectra Energy stock awards resulting from the spin-off conversion ratio, currently held by both Duke Energy and Spectra Energy employees, and reflects the related adjustments to the associated exercise prices.

In addition to the conversion of the Duke Energy stock options noted above, Spectra Energy granted 2,199,600 non-qualified stock options (fair value of $15 million, market price of $6.71/share) during 2007. Under the terms of the LTIP, the exercise price of a non-qualified stock option shall not be less than 100% of the fair market value of Spectra Energy common stock on the date of grant, and the maximum option term is ten years. The options issued in 2007 vest ratably over three years. Spectra Energy issues new shares upon exercising or vesting of share-based awards. The Black-Scholes option-pricing model was used to estimate the fair value of options at grant date. The weighted-average grant date fair value of options granted in 2007, and the significant assumptions used in determining the underlying fair value of each option granted, on the date grant were as follows:

Weighted-Average Assumptions for Option Pricing

Risk-free rate of return	4.4%
Expected life	7 years
Expected volatility	29.5%
Expected dividend yield	3.4%

The risk-free rate of return was determined based on a yield curve of U.S. Treasury rates ranging from six months to ten years and a period commensurate with the expected life of the options granted. The expected volatility was established based on historical volatility and implied volatility of a group of 12 peer company stock prices. The expected dividend yield was determined based on the company s annual dividend amount as a percentage of the average stock price at the time of grant.

There were no options granted to Spectra Energy employees during 2006 or 2005. On December 31, 2006 and 2005, Spectra Energy employees had 6 million and 16 million exercisable Duke Energy options, respectively, with weighted-average exercise prices of $31 and $32, respectively. Coincident with the spin-off of Spectra Energy, all exercisable Duke Energy options were converted in accordance with the share conversion guidelines on a two to one basis, with no change to overall intrinsic value. The total intrinsic value of options exercised during 2007, 2006 and 2005 was $6 million, $22 million and $14 million, respectively. Cash received by Spectra Energy from options exercised during 2007 was $18 million. Spectra Energy recognized a nominal tax benefit since the options exercised during 2007 were predominately held by Duke Energy employees. As of December 31, 2007, Spectra Energy expects to recognize $9 million of future compensation cost related to stock options over a weighted-average period of one year.

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Stock Awards Activity

	Performance Awards		Phantom Stock Awards		Other Stock Awards	
	Shares	Weighted Average Grant Date Fair Value	Shares	Weighted Average Grant Date Fair Value	Shares	Weighted Average Grant Date Fair Value
			(shares in thousands)			
Outstanding at December 31, 2006(a)	2,063	$ 23	1,338	$ 27	213	$ 27
Granted			378	26		
Vested	(715)	22	(554)	24	(34)	24
Forfeited	(100)	21	(55)	26	(18)	27
Outstanding at December 31, 2007	1,248	23	1,107	27	161	28
Awards expected to vest	1,188	23	1,086	27	148	28

(a) Represents the Spectra Energy stock awards resulting from the spin-off conversion ratio, currently held by both Duke Energy and Spectra Energy employees.

Performance Awards

Stock-based performance awards outstanding as of the spin-off of Spectra Energy generally vest over three years. Vesting for certain converted stock-based performance awards can occur in three years, at the earliest, if performance metrics are met. The unvested and outstanding performance awards granted 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. Coincident with the spin-off, each outstanding Duke Energy Performance award was converted into a Spectra Energy Performance Share and a Duke Energy Performance Share. Measurement of the TSR is now based upon the two equity components, weighted 50% each, consisting of Duke Energy common stock and Spectra Energy common stock, using the post-distribution Duke Energy stock price and the post-distribution Spectra Energy stock price, respectively, as the basis of measurement.

Spectra Energy did not award shares to employees in 2007. Duke Energy awarded 790,230 shares (fair value of $14 million) to employees of Spectra Energy in 2006 and 1,005,020 shares (fair value of $27 million based on the market price of Duke Energy s common stock at the grant date) to Spectra Energy employees in 2005.

The total fair value of shares vested was $16 million in 2007, and $3 million in each of 2006 and 2005. As of December 31, 2007, Spectra Energy expects to recognize $3 million of future compensation cost related to performance awards over a weighted-average period of less than one year.

Phantom Stock Awards

Phantom stock awards outstanding as of the spin-off generally vest over periods from immediate to five years. Stock-based phantom awards granted under the 2007 LTIP generally vest over three years. Spectra Energy awarded 377,500 phantom awards (fair value of $10 million) to employees of Spectra Energy in the year ended December 31, 2007.

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Phantom stock awards outstanding under Duke Energy s 1998 Long-term Incentive Plan (the 1998 Plan) generally vest over periods from immediate to five years. Duke Energy awarded 582,040 shares (fair value of $17 million) to Spectra Energy employees based on the market price of Duke Energy s common stock at the grant dates in 2006 and 924,170 shares (fair value of $25 million) in 2005.

The total fair value of the shares vested was $13 million in 2007, $16 million in 2006 and $9 million in 2005. As of December 31, 2007, Spectra Energy expects to recognize $11 million of future compensation cost related to phantom stock awards over a weighted-average period of two years.

Other Stock Awards

Other stock awards outstanding under the 1998 Plan generally vest over periods from three to five years. Duke Energy awarded 41,000 shares (fair value of $1 million) to Spectra Energy employees based on the market price of Duke Energy s common stock at the grant dates in 2006 and 47,000 shares (fair value of $1 million) in 2005.

The total fair value of the shares vested was less than $1 million for each of 2007, 2006 and 2005. As of December 31, 2007, Spectra Energy expects to recognize less than $1 million of future compensation cost related to other stock awards over a weighted-average period of two years.

22. Employee Benefit Plans

Retirement Plans. Up until the January 2, 2007 spin-off of the natural gas businesses by Duke Energy, Spectra Energy and its U.S. subsidiaries participated in Duke Energy s qualified and non-qualified non-contributory defined benefit (DB) retirement plans. The qualified plan covered 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.

Effective with the separation from Duke Energy, Spectra Energy established a new qualified non-contributory DB retirement plan for U.S. employees and new non-qualified plans for various executive retirement and savings plans. Benefits provided are substantially the same as those previously provided by Duke Energy. In accordance with the separation agreement with Duke Energy, net qualified pension plan assets of $49 million and $52 million in liabilities associated with various executive retirement and savings plans were transferred to Spectra Energy.

In addition, Spectra Energy s Westcoast subsidiary maintains qualified and non-qualified contributory and non-contributory DB and defined contribution (DC) retirement plans covering substantially all employees of its Canadian operations. The DB plans provide retirement benefits based on each plan participant s years of service and final average earnings. Under the DC plan, 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. Spectra Energy also provides non-qualified defined benefit supplemental pensions to all employees who retire under a defined benefit qualified pension plan and whose pension is limited by the maximum pension limits under the Income Tax Act (Canada). Spectra Energy reports its Canadian benefit plans separately due to actuarial assumption differences.

Spectra Energy s policy is to fund amounts for its U.S. retirement plans on an actuarial basis to provide assets sufficient to meet benefits to be paid to plan participants. Spectra Energy did not make any contributions to its U.S. retirement plan in 2007. Duke Energy did not make any contributions to its defined benefit retirement plan in 2006 or 2005. Spectra Energy does not anticipate making contributions in 2008.

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Spectra Energy s policy is to fund the Canadian qualified 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 plan are determined in accordance with the terms of the plan. Spectra Energy made contributions to the Canadian qualified DB plans of approximately $41 million in 2007, $44 million in 2006 and $42 million in 2005. Spectra Energy also made contributions to the DC plan of $5 million in 2007, $4 million in 2006 and $3 million in 2005. Spectra Energy anticipates making contributions totaling $36 million to the Canadian qualified DB plans in 2008.

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 for both the U.S. and Canadian plans. The average remaining service period of the active employees covered by the non-qualified DB retirement plans is nine years for the U.S. and 13 years for the Canadian plans, respectively. Spectra Energy determines the market-related value of plan assets using a calculated value that recognizes changes in fair value of the plan assets over five years for the U.S. plans and over three years for the Canadian plans.

Incremental Effect of the Adoption of SFAS No. 158 on the Consolidated Balance Sheet As of December 31, 2006

Spectra 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.

	Before Application of SFAS No. 158	Adjustment	After Application of SFAS No. 158
		(in millions)	
Accrued pension and other post-retirement liabilities(a)	$ (223)	$ (69)	$ (292)
Intangible assets	6	(6)	
Pre-funded pension costs			
Regulatory assets			
Deferred income tax assets	32	27	59
Accumulated other comprehensive income, net of tax	61	48	109
Total recognized	$ (124)	$	$ (124)

(a) Includes approximately $10 million that is reflected in Other within Current Liabilities in the Consolidated Balance Sheet at December 31, 2006.

Qualified Pension Plans

The table below provides the fair value of plan assets and the projected benefit obligation for the U.S. and Canadian plans. The accumulated benefit obligation for the U.S. plan was $448 million at December 31, 2007, and $703 million at December 31, 2007 and $589 million at September 30, 2006 for the Canadian plans.

The fair value of Duke Energy s U.S. plan assets (excluding Cinergy) was $3,022 million as of September 30, 2006, including plan assets related to discontinued operations. The projected benefit obligation of Duke Energy s U.S. plans (excluding Cinergy) was $2,847 million as of September 30, 2006 and the accumulated benefit obligation was $2,719 million, including obligations related to discontinued operations.

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Qualified Pension Plans Change in Projected Benefit Obligation and Change in Fair Value of Plan Assets

	U.S.	Canada	
	2007	2007	2006
		(in millions)	
Change in Projected Benefit Obligation			
Projected benefit obligation, January 1	$ 476	$ 653	$ 616
Effects of eliminating early measurement date		5	
Service cost	9	15	13
Interest cost	26	35	31
Actuarial losses (gains)	(7)	(6)	20
Participant contributions		3	3
Benefits paid	(40)	(33)	(32)
Foreign currency translation effect		106	2
Projected benefit obligation, December 31	464	778	653
Change in Fair Value of Plan Assets			
Plan assets, January 1	525	525	475
Effects of eliminating early measurement date		39	
Actual return on plan assets	40	7	32
Benefits paid	(40)	(33)	(32)
Employer contributions		38	45
Plan participants contributions		3	3
Foreign currency translation effect		91	2
Plan assets, December 31	525	670	525
Funded status	61	(108)	(128)
Contributions between measurement date and year end			12
Net amount recognized(a)	$ 61	$ (108)	$ (116)

(a) Recognized in Other Assets for the U.S. plans and Other Deferred Credits and Regulatory Liabilities for the Canadian plans on the Consolidated Balance Sheets.

Qualified Pension Plans Amounts Recognized in Accumulated Other Comprehensive Income

	U.S.	Canada	
	December 31, 2007	December 31, 2007	2006
		(in millions)	
Prior service costs	$ 2	$ 7	$ 8
Net actuarial loss	47	146	132
Net reduction of AOCI	$ 49	$ 153	$ 140

Qualified Pension Plans with Benefit Obligation in Excess of Plan Assets

	Canada December 31,	
	2007	2006
	(in millions)	
Projected benefit obligation	$ 492	$ 637
Accumulated benefit obligation	457	576
Fair value of plan assets	419	511

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Qualified Pension Plans Components of Net Periodic Pension Costs

The following table shows the components of the pre-tax net periodic pension costs for Spectra Energy s U.S. and Canadian retirement plans for 2007 and the Canadian retirement plan for 2006 and 2005. Spectra Energy s pre-tax net periodic pension benefit cost for the U.S. plans included in continuing operations, as allocated by Duke Energy, was $1 million in 2006 and $4 million in 2005. These amounts exclude pre-tax pension cost of $11 million in 2006 and $17 million in 2005 related to entities transferred to Duke Energy, which are reflected in Income (Loss) From Discontinued Operations, Net of Tax, in the Consolidated Statements of Operations.

	U.S.	Canada		
	2007	2007	2006	2005
		(in millions)		
Net Periodic Pension Cost				
Service cost benefit earned during the year	$ 9	$ 15	$ 13	$ 9
Interest cost on projected benefit obligation	26	35	31	29
Expected return on plan assets	(36)	(42)	(33)	(27)
Amortization of prior service cost	1	1	1	1
Amortization of loss	6	7	10	4
Net periodic pension cost	6	16	22	16
Other Changes in Plan Assets and Benefit Obligations Recognized in Other Comprehensive Income				
Current year actuarial gain (loss)	(11)	30		
Amortization of actuarial gain (loss)	(6)	(7)		
Amortization of prior service cost (credit)	(1)	(1)		
Effects of eliminating early measurement date		(27)		
Foreign currency translation effect		18		
Total decrease (increase) in other comprehensive income	(18)	13		
Total recognized in net periodic pension cost and other comprehensive income	$ (12)	$ 29	$ 22	$ 16

At December 31, 2007, approximately $3 million and $6 million of actuarial losses will be amortized from accumulated other comprehensive income into net periodic benefit cost in 2008 for the U.S. and Canadian pension plans, respectively.

Qualified Pension Plans Assumptions Used for Pension Benefits Accounting

	U.S.	Canada		
	2007	2007	2006	2005
Benefit Obligations				
Discount rate	6.00%	5.25%	5.00%	5.00%
Salary increase	5.71	3.50	3.50	3.25
Net Periodic Benefit Cost				
Discount rate	5.75	5.00	5.00	6.25
Salary increase	5.71	3.50	3.25	3.25
Expected long-term rate of return on plan assets	8.00	7.25	7.25	7.50

The discount rate used to determine the pension obligation for the Spectra Energy U.S. plans is the rate at which the pension obligations could be effectively settled. This rate is developed from yields on available high-quality bonds and reflects the plan s expected cash flows.

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The Canadian plan s discount rate used to determine the pension obligation is prescribed as the yield on Canadian corporate AA bonds at the measurement date of December 31. 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

	U.S.		Canada		
Asset Category	**Target Allocation**	**December 31, 2007**	**Target Allocation**	**December 31, 2007**	**December 31, 2006**
Canadian equity securities	%	%	30%	33%	29%
U.S. equity securities	45	44	15	15	15
Other equity securities	20	20	15	15	16
Debt securities	35	36	40	37	40
Total	100%	100%	100%	100%	100%

Spectra 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. Other equities and debt securities are held for diversification. Investments within asset classes are to be diversified to achieve broad market participation and reduce the effect of individual managers or investments. Spectra 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 8.00% as of December 31, 2007 for the Spectra 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 applied against the U.S. plans asset mix of approximately 35% income securities and 65% equities.

The Canadian plan assets for qualified 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.

The long-term rate of return of 7.25%, as of December 31, 2007, for the Canadian plan 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 average returns expected by asset classes were 8.65% for equities and 5.15% for fixed income securities. The target asset allocation is 60% in equities and 40% in fixed income securities.

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Qualified Pension Plans Expected Benefit Payments

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid over the next five years and thereafter:

	U.S.	Canada
	(in millions)	
2008	$ 41	$ 37
2009	41	37
2010	39	39
2011	42	40
2012	47	42
2013 2017	239	247

Non-Qualified Pension Plans

Spectra Energy maintains a non-qualified, non-contributory defined benefit retirement plan which covers certain U.S. executives. There are no plan assets. The projected benefit obligation was $19 million as of December 31, 2007. During 2006 and 2005, Duke Energy maintained and Spectra Energy participated in, a non-qualified, non-contributory defined benefit retirement plan which covered certain U.S. executives. There were no plan assets. The projected benefit obligation was $84 million as of September 30, 2006, which included obligations associated with discontinued operations.

Spectra Energy also maintains a non-qualified, non-contributory defined benefits plan for its Canadian employees. There are no plan assets. The projected benefit obligation was $99 million as of December 31, 2007 and $88 million as of September 30, 2006.

Non-Qualified Pension Plans Change in Projected Benefit Obligation and Fair Value of Plan Assets

	U.S.	Canada	
	2007	2007	2006
		(in millions)	
Change in Projected Benefit Obligation			
Projected benefit obligation, January 1	$ 18	$ 88	$ 84
Effects of eliminating early measurement date		(1)	
Service cost	1	1	1
Interest cost	1	5	4
Actuarial losses / (gains)	1	(2)	3
Benefits paid	(2)	(5)	(4)
Foreign currency translation effect		13	
Projected benefit obligation, December 31	19	99	88
Change in Fair Value of Plan Assets			
Plan assets, January 1			
Benefits paid	(2)	(5)	(4)
Employer contributions	2	5	4
Fair value of plan assets, December 31			
Funded status	(19)	(99)	(88)
Contributions between measurement date and year end			2

Amount recognized, December 31(a)	$ (19)	$ (99)	$ (86)

(a) Amounts are reflected in Other Deferred Credits and Regulatory Liabilities within the Consolidated Balance Sheets.

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For the U.S. plan, the accumulated benefit obligation was $16 million at December 31, 2007. For the Canadian plan, the accumulated benefit obligation was $98 million at December 31, 2007 and $83 million at September 30, 2006.

Non-Qualified Pension Plans Amounts Recognized in Accumulated Other Comprehensive Income

Net actuarial losses for the Canadian non-qualified pension plans totaling $24 million at December 31, 2007 and $25 million at December 31, 2006 were recognized in Accumulated Other Comprehensive Income within the Consolidated Balance Sheets.

At December 31, 2007, approximately $1 million of unrecognized losses was included in Accumulated Other Comprehensive Income in the Consolidated Balance Sheets that will be recognized in net periodic non-qualified pension costs in 2008 for the Canadian Plan. At December 31, 2007, amounts recognized in Accumulated Other Comprehensive Income for the U.S. Plan were less than $1 million.

Non-Qualified Pension Plans with Benefit Obligation in Excess of Plan Assets

	U.S.	Canada	
	2007	2007	2006
		(in millions)	
Projected benefit obligation	$ 19	$ 99	$ 88
Accumulated benefit obligation	16	98	83

Non-Qualified Pension Plans Components of Net Periodic Pension Costs

The following tables show the components of the net periodic pension costs for Spectra Energy s U.S. and Canadian non-qualified retirement plans for 2007 and the Canadian non-qualified retirement plan for 2006 and 2005.

Spectra Energy s pre-tax net periodic pension cost for the U.S. plan, as allocated by Duke Energy, was $1 million for both 2006 and 2005. These amounts exclude pre-tax pension cost of $3 million in each of 2006 and 2005, related to entities transferred to Duke Energy, which are reflected in Income (Loss) From Discontinued Operations, Net of Tax, in the Consolidated Statements of Operations.

	U.S.	Canada		
	2007	2007	2006	2005
		(in millions)		
Net Periodic Pension Cost				
Service cost benefit earned during the year	$ 1	$ 1	$ 1	$ 1
Interest cost on projected benefit obligation	1	5	4	4
Amortization of loss		1	1	
Net periodic pension cost	2	7	6	5
Other Changes in Plan Assets and Benefits Obligations Recognized in Other Comprehensive Income				
Current year actuarial gain		(3)		
Amortization of actuarial gain		(1)		
Effects of eliminating early measurement date		(1)		
Foreign currency translation effect		4		
Total decrease (increase) in other comprehensive income		(1)		
Total recognized in net periodic pension cost and other comprehensive income	$ 2	$ 6	$ 6	$ 5

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Non-Qualified Pension Plans Assumptions Used for Pension Benefits Accounting

	U.S.	Canada		
	2007	2007	2006	2005
Benefit Obligations				
Discount rate	6.00%	5.25%	5.00%	5.00%
Salary increase	5.10	3.50	3.50	3.25
Net Periodic Benefit Cost				
Discount rate	5.75	5.00	5.00	6.25
Salary increase	5.10	3.50	3.25	3.25

For the Spectra Energy U.S. plans the discount rate for pension purposes is the rate at which the pension obligations could be effectively settled. The rate is developed from yields on available high-quality bonds and reflects the plan s expected cash flows.

The Canadian plan s discount rate used to determine the pension obligation is prescribed as the yield on Canadian corporate AA bonds at the measurement date of December 31. 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 Pension Plans Expected Benefit Payments

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid over the next five years and thereafter:

	U.S.	Canada
	(in millions)	
2008	$ 2	$ 5
2009	2	5
2010	2	6
2011	2	6
2012	2	6
2013 2017	9	24

Contributions for the non-qualified pension plans are equal to that of benefit payments, therefore, Spectra Energy expects to contribute $2 million to the U.S. plan in 2008 and $5 million to the Canadian plan in 2008.

Other Post-Retirement Benefit Plans

U.S. Other Post-Retirement Benefits. Spectra Energy and most of its subsidiaries provide certain 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. In accordance with the separation agreement, $194 million in liabilities associated with other post-retirement benefits were transferred to Spectra Energy upon separation from Duke Energy.

These benefit costs are accrued over an employee s active service period to the date of full benefits eligibility. The net unrecognized transition obligation resulting from the adoption in 1993 of SFAS No. 106, Employers Accounting for Postretirement Benefits Other than Pensions, is amortized over approximately 20 years, with six years remaining. 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 12 years.

The fair value of Spectra Energy s plan assets was $86 million as of December 31, 2007 and the accumulated post-retirement benefit obligation was $248 million.

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The fair value of Duke Energy s plan assets, in which Spectra Energy employees participated prior to the separation, was $237 million as of September 30, 2006, which includes assets attributable to discontinued operations and the post-retirement benefit obligation was $767 million, which include obligations related to discontinued operations.

Spectra Energy s pre-tax net periodic post-retirement benefit cost for the U.S. plan was $18 million in 2007. Spectra Energy s pre-tax net periodic post-retirement benefit cost included in continuing operations, as allocated by Duke Energy, was $9 million for both 2006 and 2005. These amounts exclude pre-tax post retirement benefit cost of $10 million in both 2006 and 2005 related to entities transferred to Duke Energy, which are reflected in Income From Discontinued Operations, Net of Tax, in the Consolidated Statements of Operations.

Canadian Other Post-Retirement Benefits. Spectra Energy provides health care and life insurance benefits for retired employees on a non-contributory basis for its Canadian Operations. 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 applies 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 Plans Change in Projected Benefit Obligation and

Fair Value of Plan Assets

	U.S.	Canada	
	2007	2007	2006
		(in millions)	
Change in Benefit Obligation			
Accumulated post-retirement benefit obligation, January 1	$ 279	$ 91	$ 117
Effects of eliminating early measurement date		1	
Service cost	1	3	4
Interest cost	15	5	7
Plan participants contribution	2		
Actuarial gain	(28)	(2)	(34)
Medicare subsidy receivable	3		
Benefits paid	(24)	(4)	(4)
Foreign currency translation effect		14	1
Accumulated post-retirement benefit obligation, December 31	248	108	91
Change in Fair Value of Plan Assets			
Plan assets, January 1	89		
Actual return on plan assets	3		
Benefits paid	(24)	(4)	(4)
Employer contributions	16	4	4
Plan participants contributions	2		
Plan assets, December 31	86		
Funded status, December 31	(162)	(108)	(91)
Contributions made between measurement date and year end			1
Amount recognized, December 31(a)	$ (162)	$ (108)	$ (90)

(a) Recognized in Other Deferred Credits and Regulatory Liabilities on the Consolidated Balance Sheets.

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Other Post-Retirement Benefit Plans Amounts Recognized in Accumulated Other Comprehensive Income

	U.S. December 31, 2007	Canada December 31, 2007	Canada December 31, 2006
		(in millions)	
Prior service costs	$	$ (11)	$ (11)
Net actuarial loss	38	13	14
SFAS No. 106 transition obligation	26		
Net reduction of AOC I	$ 64	$ 2	$ 3

At December 31, 2007, approximately $5 million of transition obligation and $2 million of actuarial loss were included in AOCI in the Consolidated Balance Sheets that will be recognized in net periodic qualified pension costs in 2008.

	U.S. 2007	Canada 2007	Canada 2006	Canada 2005
		(in millions)		
Other Post-Retirement Benefit Plans Components of Net Periodic Benefit Cost				
Service cost benefit earned during the year	$ 1	$ 3	$ 4	$ 3
Interest cost on accumulated post-retirement benefit obligation	15	5	7	6
Expected return on plan assets	(6)			
Amortization of net transition liability	4			
Amortization of prior service credit	(2)	(1)	(1)	(1)
Amortization of loss	6		2	1
Net periodic other post-retirement benefit cost	18	7	12	9
Other Changes in Plan Assets and Benefit Obligations Recognized in Other Comprehensive Income				
Current year actuarial loss	(26)	(2)		
Amortization of actuarial gain (loss)	(4)	(1)		
Amortization of prior service credit	2	1		
Amortization of transition asset/obligation	(5)			
Foreign currency translation effect		1		
Total decrease (increase) in other comprehensive income	(33)	(1)		
Total recognized in net periodic benefit cost and other comprehensive income	$ (15)	$ 6	$ 12	$ 9

Other Post-Retirement Benefits Plans Assumptions Used

	U.S. 2007	Canada 2007	Canada 2006	Canada 2005
Benefit Obligations				
Discount rate	6.00%	5.25%	5.00%	5.00%
Salary increase	5.70	3.50	3.50	3.25
Net Periodic Benefit Cost				

Discount rate	5.75	5.00	5.00	6.25
Salary increase	5.70	3.50	3.25	3.25
Expected return on plan assets for post-retirement medical plans	6.65	n/a	n/a	n/a
Expected return on plan assets for post-retirement life plans	6.90	n/a	n/a	n/a

n/a indicates not applicable

For the Spectra Energy U.S. plans the discount rate used to determine the post-retirement obligation is the rate at which the pension obligations could be effectively settled. This rate is developed from yields on available high-quality bonds and reflects the plan s expected cash flows.

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The Canadian plan s discount rate used to determine the post-retirement obligation is prescribed as the yield on Canadian corporate AA bonds at the measurement date of December 31. The yield is selected based on bonds with cash flows that match the timing and amount of the expected benefit payments under the plan.

Assumed Health Care Cost Trend Rates

	U.S.	Canada	
	2007	2007	2006
Health care cost trend rate assumed for next year	7.50%	8.00%	8.00%
Rate to which the cost trend is assumed to decline (the ultimate trend rate)	5.00%	5.00%	5.00%
Year that the rate reaches the ultimate trend rate	2013	2010	2009

Sensitivity to Changes in Assumed Health Care Cost Trend Rates

	U.S.		Canada	
	1% Point Increase	1% Point Decrease	1% Point Increase	1% Point Decrease
	(in millions)			
Effect on total service and interest costs	$ 1	$ (1)	$ 1	$ (1)
Effect on post-retirement benefit obligation	14	(12)	8	(7)

Other Post-Retirement Plan Assets

Asset Category	U.S. December 31, 2007
Equity securities	51%
Debt securities	40
Other assets	9
Total	100%

Spectra Energy s U.S. assets for 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. Asset allocation targets, which are the same as those of the qualified pension assets 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. Investments within asset classes are diversified to achieve broad market participation and reduce the impact of individual managers or investments. Spectra 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 8.00% as of December 31, 2007 for the Spectra 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 applied against the U.S. plans master trust asset mix of approximately 35% income securities and 65% equities.

Spectra Energy also invests other post-retirement assets in the Spectra Energy Corp Employee Benefits Trust (VEBA I) and the Spectra Energy Corp Post-Retirement Medical Benefits Trust (VEBA II). The investment objective of the VEBAs 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.

The asset allocation table above includes the other post-retirement benefit assets held in the master trusts, VEBA I and VEBA II. Assets held in the master trusts represent 39% of the total, while the assets of VEBA I represent 32% of the total and the assets of VEBA II represent 29% of the total.

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Other Post-Retirement Plans Benefit Payments and Receipts

Spectra Energy expects to make future benefit payments, which reflect expected future service, as appropriate. Spectra Energy also 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.

Benefit Payments	U.S.	Canada
	(in millions)	
2008	$ 23	$ 5
2009	24	5
2010	25	5
2011	25	5
2012	25	6
2013 2017	120	28

Medicare Part D Subsidy Receipts	U.S.
	(in millions)
2008	$ 2
2009	3
2010	3
2011	3
2012	3
2013 2017	12

Spectra Energy anticipates making contributions of $21 million in 2008 for the U.S. plans and $5 million for the Canadian plans.

Retirement Savings Plan

During 2006 and 2005, Duke Energy sponsored, and Spectra Energy participated in, employee savings plans that covered substantially all U.S. employees. Most employees participated in a matching contribution formula where Duke Energy provided a matching contribution generally equal to 100% of before-tax employee contributions, of up to 6% of eligible pay per pay period. Effective with the separation from Duke Energy, Spectra Energy established an employee savings plan that provides benefits substantially the same as those provided under the Duke Energy plan. Spectra Energy expensed pre-tax employer matching contributions of $9 million in 2007, and, as allocated by Duke Energy, of $8 million in 2006 and $7 million in 2005. These amounts exclude pre-tax expenses of $14 million in 2006 and $13 million in 2005 related to entities transferred to Duke Energy, which are reflected in Income (Loss) From Discontinued Operations, Net of Tax.

23. Consolidating Financial Information

In December 2007, Spectra Energy Corp agreed to fully and unconditionally guarantee the payment of principal and interest under all series of notes outstanding under the Senior Indenture of Spectra Capital, the wholly owned, consolidated subsidiary of Spectra Energy Corp. In accordance with Securities and Exchange Commission rules, the following condensed consolidating financial information is presented. The information shown for Spectra Energy Corp and Spectra Capital is presented utilizing the equity method of accounting for investments in subsidiaries, as required. The non-guarantor subsidiaries column represents all wholly owned subsidiaries of Spectra Capital. This information should be read in conjunction with Spectra Energy s accompanying consolidated financial statements and notes thereto.

Spectra Energy Corp was incorporated on July 28, 2006, and therefore, financial information for 2005 is not applicable.

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Spectra Energy Corp

Condensed Consolidating Statement of Operations

Year Ended December 31, 2007

(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Spectra Energy Corp Consolidated
Total operating revenues	$	$	$ 4,742	$	$ 4,742
Total operating expenses	46	6	3,261		3,313
Gains on sales of other assets and other, net			13		13
Operating income (loss)	(46)	(6)	1,494		1,442
Equity in earnings of unconsolidated affiliates			596		596
Equity in earnings of subsidiaries	986	1,439		(2,425)	
Other income and expenses, net	3	1	49		53
Interest expense		218	415		633
Minority interest expense			71		71
Earnings from continuing operations before income taxes	943	1,216	1,653	(2,425)	1,387
Income tax expense (benefit) from continuing operations	(14)	230	227		443
Income from continuing operations	957	986	1,426	(2,425)	944
Income from discontinued operations, net of tax			13		13
Net income	$ 957	$ 986	$ 1,439	$ (2,425)	$ 957

Spectra Energy Corp

Condensed Consolidating Statement of Operations

Year Ended December 31, 2006

(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Spectra Energy Corp Consolidated
Total operating revenues	$	$ (26)	$ 4,558	$	$ 4,532
Total operating expenses		2	3,332		3,334
Gains on sales of other assets and other, net			47		47
Operating income (loss)		(28)	1,273		1,245
Equity in earnings of unconsolidated affiliates			606		606

Equity in earnings of subsidiaries		1,184			(1,184)			
Other income and expenses, net		41		89				130
Interest expense		373		232				605
Minority interest expense				45				45
Earnings from continuing operations before income taxes		824		1,691		(1,184)		1,331
Income tax expense (benefit) from continuing operations		(151)		546				395
Income from continuing operations		975		1,145		(1,184)		936
Income from discontinued operations, net of tax		269		39				308
Net income	$	$ 1,244	$	1,184	$	(1,184)	$	1,244

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Spectra Energy Corp

Condensed Consolidating Statement of Operations

Year Ended December 31, 2005

(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Spectra Energy Corp Consolidated
Total operating revenues	n/a	$ (8)	$ 9,462	$	$ 9,454
Total operating expenses	n/a	3	8,120		8,123
Gains on sales of other assets and other, net	n/a		522		522
Operating income (loss)	n/a	(11)	1,864		1,853
Equity in earnings of unconsolidated affiliates	n/a		355		355
Equity in earnings of subsidiaries		891		(891)	
Gain on sales and impairments of equity method investments	n/a		1,245		1,245
Other income and expenses, net	n/a	35	33		68
Interest expense	n/a	241	434		675
Minority interest expense	n/a		511		511
Earnings from continuing operations before income taxes	n/a	674	2,552	(891)	2,335
Income tax expense from continuing operations	n/a		926		926
Income from continuing operations	n/a	674	1,626	(891)	1,409
Loss from discontinued operations, net of tax	n/a		(731)		(731)
Income before cumulative effect of change in accounting principle	n/a	674	895	(891)	678
Cumulative effect of change in accounting principle, net of tax and minority interest	n/a		(4)		(4)
Net income	n/a	$ 674	$ 891	$ (891)	$ 674

Spectra Energy Corp

Condensed Consolidating Balance Sheet

December 31, 2007

(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Spectra Energy Corp Consolidated

Cash and cash equivalents	$	$	$ 94	$	$ 94
Receivables (payables) consolidated subsidiaries	(9)	269	(255)	(5)	
Receivables other	2	8	897		907
Other current assets	8	1	369		378
Total current assets	1	278	1,105	(5)	1,379
Investments in and loans to unconsolidated affiliates		3	1,777		1,780
Investments in consolidated subsidiaries	7,434	10,281		(17,715)	
Advances receivable (payable) consolidated subsidiaries	(752)	2,369	(1,617)		
Goodwill			3,948		3,948
Other assets	100	210	321		631
Property, plant and equipment, net		2	14,298		14,300
Regulatory assets and deferred debits	5	7	920		932
Total Assets	$ 6,788	$ 13,150	$ 20,752	$ (17,720)	$ 22,970
Accounts payable (receivable) consolidated subsidiaries	$ 5	$ 42	$ (42)	$ (5)	$
Accounts payable other	7	107	249		363
Accrued taxes payable (receivable)	(278)	233	130		85
Current maturities of long-term debt			338		338
Other current liabilities	26	544	1,066		1,636
Total current liabilities	(240)	926	1,741	(5)	2,422
Long-term debt		2,975	5,370		8,345
Deferred credits and other liabilities	171	1,815	2,554		4,540
Minority interests			806		806
Total stockholders equity	6,857	7,434	10,281	(17,715)	6,857
Total Liabilities and Stockholders Equity	$ 6,788	$ 13,150	$ 20,752	$ (17,720)	$ 22,970

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Spectra Energy Corp

Condensed Consolidating Balance Sheet

December 31, 2006

(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Spectra Energy Corp Consolidated
Cash and cash equivalents	$	$ (44)	$ 343	$	$ 299
Receivables (payables) consolidated subsidiaries		1,035	(1,035)		
Receivables, other		9	770		779
Other current assets		16	531		547
Total current assets		1,016	609		1,625
Investments in and loans to unconsolidated affiliates			1,618		1,618
Investments in consolidated subsidiaries		8,107		(8,107)	
Advances receivable (payable) consolidated subsidiaries		(669)	669		
Goodwill			3,507		3,507
Other assets		16	216		232
Property, plant and equipment, net			12,394		12,394
Regulatory assets and deferred debits		10	959		969
Total Assets	$	$ 8,480	$ 19,972	$ (8,107)	$ 20,345
Accounts payable (receivable) consolidated subsidiaries	$	$ 47	$ (47)	$	$
Accounts payable other			246		246
Accrued taxes payable (receivable)		(325)	539		214
Current maturities of long-term debt			550		550
Other current liabilities		411	937		1,348
Total current liabilities		133	2,225		2,358
Long-term debt		2,604	5,122		7,726
Deferred credits and other liabilities		104	3,953		4,057
Minority interests			565		565
Total member s equity		5,639	8,107	(8,107)	5,639
Total Liabilities and Member s Equity	$	$ 8,480	$ 19,972	$ (8,107)	$ 20,345

Spectra Energy Corp

Condensed Consolidating Statements of Cash Flows

Year Ended December 31, 2007

(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Spectra Energy Corp Consolidated
Net cash provided by (used in) operating activities	$ (208)	$ (131)	$ 1,806	$	$ 1,467
Net cash used in investing activities		(154)	(1,390)		(1,544)
Net cash provided by (used in) financing activities	208	329	(728)		(191)
Effect of exchange rate changes on cash			63		63
Net increase (decrease) in cash and cash equivalents		44	(249)		(205)
Cash and cash equivalents at beginning of period		(44)	343		299
Cash and cash equivalents at end of period	$	$	$ 94	$	$ 94

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Spectra Energy Corp

Condensed Consolidating Statements of Cash Flows

Year Ended December 31, 2006

(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Spectra Energy Corp Consolidated
Net cash provided by operating activities	$	$ 116	$ 578	$	$ 694
Net cash provided by investing activities		521	1,048		1,569
Net cash used in financing activities		(682)	(1,772)		(2,454)
Effect of exchange rate changes on cash			(1)		(1)
Net decrease in cash and cash equivalents		(45)	(147)		(192)
Cash and cash equivalents at beginning of period		1	490		491
Cash and cash equivalents at end of period	$	$ (44)	$ 343	$	$ 299

Spectra Energy Corp

Condensed Consolidating Statements of Cash Flows

Year Ended December 31, 2005

(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Spectra Energy Corp Consolidated
Net cash provided by (used in) operating activities	n/a	$ (276)	$ 1,345	$	$ 1,069
Net cash provided by investing activities	n/a	347	894		1,241
Net cash used in financing activities	n/a	(79)	(2,262)		(2,341)
Effect of exchange rate changes on cash	n/a		6		6
Net decrease in cash and cash equivalents	n/a	(8)	(17)		(25)
Cash and cash equivalents at beginning of period	n/a	9	507		516
Cash and cash equivalents at end of period	n/a	$ 1	$ 490	$	$ 491

24. Quarterly Financial Data (Unaudited)

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
	(in millions, except per share amounts)				
2007					
Operating revenues	$ 1,401	$ 985	$ 959	$ 1,397	$ 4,742
Operating income	420	302	333	387	1,442
Net income	236	196	234	291	957
Earnings per share	$ 0.37	$ 0.31	$ 0.37	$ 0.46	$ 1.51
2006					
Operating revenues	$ 1,485	$ 981	$ 869	$ 1,197	$ 4,532
Operating income	385	321	252	287	1,245
Net income	222	320	447	255	1,244

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Unusual or Infrequent Items

During the second quarter of 2007, Spectra Energy recorded an $18 million pre-tax gain related to settlement proceeds of the Sonatrach/Sonatrading Amsterdam B.V. (Sonatrading) 2001 arbitration proceeding which is included in Income (Loss) From Discontinued Operations, Net of Tax, on the Consolidated Statements of Operations. See Note 9 for further discussion.

During the first quarter of 2006, Spectra Energy recorded a $24 million pre-tax gain on the settlement of a customer s transportation contract. See Note 3 for further discussion.

During the second quarter of 2006, Spectra Energy recorded a $55 million pre-tax other-than-temporary impairment charge included in Income (Loss) From Discontinued Operations, net of Tax related to International Energy s investment in Campeche. See Note 9 for further discussion.

During the third quarter of 2006, Spectra Energy recorded a $250 million pre-tax gain on the sale of an effective 50% interest in the Crescent JV and a $38 million additional gain on the sale of DENA s assets. Both of these gains are included in Income (Loss) From Discontinued Operations, Net of Tax. See Note 9 for further discussion.

During the fourth quarter of 2006, Spectra Energy recorded a $100 million pre-tax charge to establish a settlement reserve related to certain litigation, and a $28 million pre-tax impairment charge at International Energy as a result of the pending sale of operations in Bolivia, which is included in Income (Loss) From Discontinued Operations, Net of Tax. See Note 9 for further discussion.

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SPECTRA ENERGY CORP

SCHEDULE II VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

	Balance at Beginning of Period	Additions: Charged to Expense	Additions: Charged to Other Accounts	Deductions(a)	Balance at End of Period
			(In millions)		
December 31, 2007:					
Allowance for doubtful accounts	$ 13	$ 17	$	$ 8	$ 22
Other(b)	236	20	98	150	204
	$ 249	$ 37	$ 98	$ 158	$ 226
December 31, 2006:					
Allowance for doubtful accounts	$ 121	$ 23	$ 14	$ 145	$ 13
Other(b)	708	226	67	765	236
	$ 829	$ 249	$ 81	$ 910	$ 249
December 31, 2005:					
Allowance for doubtful accounts	$ 128	$ 21	$ 10	$ 38	$ 121
Other(b)	710	330	64	396	708
	$ 838	$ 351	$ 74	$ 434	$ 829

(a) Principally cash payments and reserve reversals. Also includes transfer of certain operations to Duke Energy in April 2006 and December 2006 as discussed in Note 9.

(b) Principally insurance related reserves, litigation and other reserves, included primarily in Regulatory and Other Deferred Credits and Other Liabilities on the Consolidated Balance Sheets.

Item 9. Changes in and Disagreements with Accountants and Accounting and Financial Disclosure.

None.

Item 9A. Controls and Procedures.

Disclosure controls and procedures are controls and other procedures that are designed to ensure that information required to be disclosed by Spectra 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 Spectra 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, Spectra 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, 2007, and, based upon this evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that these controls and procedures are effective.

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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, Spectra 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, 2007 and found no change that has materially affected, or is reasonably likely to materially affect, internal control over financial reporting.

Management s Annual Report on Internal Control over Financial Reporting

The report of management required under this Item 9A is contained in Item 8. Financial Statements and Supplementary Data, Management s Annual Report on Internal Control over Financial Reporting.

Attestation Report of Independent Registered Public Accounting Firm

The attestation report required under this Item 9A is contained in Item 8. Financial Statements and Supplementary Data, Report of Independent Registered Public Accounting Firm.

Item 9B. Other Information.

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance.

Reference to Executive Officers is included in Item 1. Business of this report. Other information in response to this item is incorporated by reference from Spectra Energy s Proxy Statement relating to Spectra Energy s 2008 annual meeting of shareholders.

Item 11. Executive Compensation.

Information in response to this item is incorporated by reference from Spectra Energy s Proxy Statement relating from Spectra Energy s 2008 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 from Spectra Energy s Proxy Statement relating to Spectra Energy s 2008 annual meeting of shareholders.

Item 13. Certain Relationships and Related Transactions, and Director Independence.

Information in response to this item is incorporated by reference from Spectra Energy s Proxy Statement relating to Spectra Energy s 2008 annual meeting of shareholders.

Item 14. Principal Accounting Fees and Services.

Information in response to this item is incorporated by reference from Spectra Energy s Proxy Statement relating to Spectra Energy s 2008 annual meeting of shareholders.

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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:

Spectra Energy Corp:

Report of Independent Registered Accounting Firm

Consolidated Statements of Operations for the Years Ended December 31, 2007, 2006 and 2005

Consolidated Balance Sheets as of December 31, 2007 and 2006

Consolidated Statements of Cash Flows for the Years Ended December 31, 2007, 2006 and 2005

Consolidated Statements of Stockholders /Member s Equity and Comprehensive Income for the Years ended December 31, 2007, 2006 and 2005

Notes to the Consolidated Financial Statements

Consolidated Financial Statement Schedule II Valuation and Qualifying Accounts and Reserves for the Years Ended December 31, 2007, 2006 and 2005

Separate 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.

(c) Exhibits See Exhibit Index immediately following the signature page.

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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: February 28, 2008

SPECTRA ENERGY CORP

(Registrant)

By: /s/ Fred J. Fowler
Fred J. Fowler

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) Fred J. Fowler*
President and Chief Executive Officer (Principal Executive Officer and Director)

(ii) Gregory L. Ebel*
Group Executive and Chief Financial Officer (Principal Financial Officer)

(iii) Sabra L. Harrington*
Vice President and Controller (Principal Accounting Officer)

(iv) Paul M. Anderson*
Chairman of the Board of Directors

Austin A. Adams*
Director

Roger Agnelli*
Director

Pamela L. Carter*
Director

William T. Esrey*
Director

Peter B. Hamilton*
Director

Dennis R. Hendrix*
Director

Michael E.J. Phelps*
Director

Martha B. Wyrsch*
Director

Date: February 28, 2008

Gregory L. Ebel, 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/ Gregory L. Ebel
Gregory L. Ebel

Attorney-In-Fact

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CONSOLIDATED FINANCIAL STATEMENTS

OF TEPPCO PARTNERS, L.P.

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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.

/s/ 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

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TEPPCO PARTNERS, L.P.

CONSOLIDATED BALANCE SHEETS

(in thousands)

	December 31, 2005	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

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TEPPCO PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF INCOME

(in thousands, except per Unit amounts)

	Years Ended December 31,		
	2005	2004 (as restated)	2003 (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.

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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

See accompanying Notes to Consolidated Financial Statements

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TEPPCO PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF CASH FLOWS (Continued)

(in thousands)

	Years Ended December 31,		
	2005	2004 (as restated)	2003 (as restated)
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.

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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.

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TEPPCO PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(in thousands)

	Years Ended December 31,		
	2005	2004 (as restated)	2003 (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.

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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 .

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TEPPCO PARTNERS, L.P.

Notes to Consolidated Financial Statements Continued

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

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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

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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.

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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.

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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.

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

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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

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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.

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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-*

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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

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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

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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

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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

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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.

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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

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accounting. The assets of the purchased companies will be integrated into our Downstream Segment 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

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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

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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	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

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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.

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(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).

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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.

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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

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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

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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 Value	Fair Value December 31, 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.

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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.

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	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

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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%

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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

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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

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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

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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

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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

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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.

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.

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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.

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%		

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(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	$

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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

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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

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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 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

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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

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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.

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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

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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 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

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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

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	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

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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.

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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

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	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

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	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

	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

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	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

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	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

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	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

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

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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

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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

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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

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TEPPCO PARTNERS, L.P.

Notes to Consolidated Financial Statements Continued

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

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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

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TEPPCO PARTNERS, L.P.

Notes to Consolidated Financial Statements Continued

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.

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EXHIBIT INDEX

Exhibit No.	Exhibit Description
2.1	Separation and Distribution Agreement by and between Duke Energy Corporation and Spectra Energy Corp, dated as of December 13, 2006 (filed as Exhibit No. 2.1 to Form 8-K of Spectra Energy Corp on December 15, 2006)
2.2	Reorganization Agreement by and among ConocoPhillips, Duke Capital LLC and DCP Midstream, LLC, dated as of May 26, 2005 (filed as Exhibit No. 10.4 to Form 10-Q of Duke Energy Corporation for the quarter ended June 30, 2005, File No. 1-4928)
2.2.1	First Amendment to Reorganization Agreement by and among ConocoPhillips, Duke Capital LLC and DCP Midstream, LLC, dated as of June 30, 2005 (filed as Exhibit No. 10.4.1 to Form 10-Q of Duke Energy Corporation for the quarter ended June 30, 2005)
2.2.2	Second Amendment to Reorganization Agreement by and among ConocoPhillips, Duke Capital LLC and DCP Midstream, LLC, dated as of July 11, 2005 (filed as Exhibit No. 10.4.2 to Form 10-Q of Duke Energy Corporation for the quarter ended June 30, 2005)
2.3	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 as Exhibit No. 10.7 to Form 10-Q of Duke Energy Corporation for the quarter ended September 30, 2001)
2.4	Spectra Energy Support Agreement dated as of January 1, 2007, between Spectra Energy Corp, Duke Energy Canada Call Co. and Duke Energy Canada Exchangeco Inc. (filed as Exhibit No. 2.2 to Form S-3 of Spectra Energy Corp on January 17, 2007)
2.5	Spectra Energy Voting and Exchange Trust Agreement dated as of January 1, 2007, between Spectra Energy Corp, Duke Energy Canada Exchangeco Inc. and Computershare Trust Company, Inc. (filed as Exhibit No. 2.3 to Form S-3 of Spectra Energy Corp on January 17, 2007)
2.6	Plan of Arrangement, as approved by the Supreme Court of British Columbia by final order dated December 15, 2006 (filed as Exhibit 2.4 to Form S-3 of Spectra Energy Corp on January 17, 2007)
3.1	Amended and Restated Certificate of Incorporation of Spectra Energy Corp (filed as Exhibit No. 3.1 to Form 8-K of Spectra Energy Corp on December 15, 2006)
3.2	Amended and Restated By-laws of Spectra Energy Corp (filed as Exhibit No. 3.2 to Form 8-K of Spectra Energy Corp on December 15, 2006)
4.1	Senior Indenture between Duke Capital Corporation and the Chase Manhattan Bank, dated as of April 1, 1998 (filed as Exhibit No. 4.1 to Form S-3 of Duke Capital Corporation on April 1, 1998, File No. 333-71297)
10.1	Tax Matters Agreement by and among Duke Energy Corporation, Spectra Energy Corp, and The Other Spectra Energy Parties, dated as of December 13, 2006 (filed as Exhibit No. 10.1 to Form 8-K of Spectra Energy Corp on December 15, 2006)
10.2	Transition Services Agreement by and between Duke Energy Corporation and Spectra Energy Corp, dated as of December 13, 2006 (filed as Exhibit No. 10.2 to Form 8-K of Spectra Energy Corp on December 15, 2006)
10.3	Employee Matters Agreement by and between Duke Energy Corporation and Spectra Energy Corp, dated as of December 13, 2006 (filed as Exhibit No. 10.3 to Form 8-K of Spectra Energy Corp on December 15, 2006)
10.3.1	First Amendment to Employee Matters Agreement, dated as of September 28, 2007, by and between Duke Energy Corporation and Spectra Energy Corp (filed as Exhibit No. 10.1 to Form 10-Q of Spectra Energy Corp for the quarter ended September 30, 2007)

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Exhibit No.	Exhibit Description
10.4	Purchase and Sale Agreement, dated as of February 24, 2005, by and between Enterprise GP Holdings LP and DCP Midstream, LLC (filed as Exhibit No. 10.25 to Form 10-K of Duke Energy Corporation for the year ended December 31, 2004)
10.5	Term Sheet Regarding the Restructuring of DCP Midstream LLC, dated as of February 23, 2005, between Duke Energy Corporation and ConocoPhillips (filed as Exhibit No. 10.26 to Form 10-K of Duke Energy Corporation for the year ended December 31, 2004)
10.6	Second Amended and Restated Limited Liability Company Agreement of DCP Midstream, LLC by and between ConocoPhillips Gas Company and Duke Energy Enterprises Corporation, dated as of July 5, 2005 (filed as Exhibit No. 10.5 to Form 10-K of Duke Energy Corporation for the year ended December 31, 2005)
10.7	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 as Exhibit No. 10.18 to Form 10-K of Duke Energy Corporation for the year ended December 31, 2002)
10.8	Loan Agreement, dated as of February 25, 2005, between DCP Midstream, LLC and Duke Capital LLC (filed as Exhibit No. 10.3 to Form 10-Q of Duke Energy Corporation for the quarter ended March 31, 2005)
+10.9	Spectra Energy Corp Directors Savings Plan (filed as Exhibit No. 10.1 to Form 8-K of Spectra Energy Corp on December 22, 2006)
+10.10	Spectra Energy Corp Executive Savings Plan (filed as Exhibit No. 10.2 to Form 8-K of Spectra Energy Corp on December 22, 2006)
+10.11	Spectra Energy Corp Executive Cash Balance Plan (filed as Exhibit No. 10.3 to Form 8-K of Spectra Energy Corp on December 22, 2006)
+10.12	Form of Change of Control Severance Agreements (filed as Exhibit No. 10.4 to Form 8-K of Spectra Energy Corp on December 22, 2006)
+10.13	Spectra Energy Corp 2007 Long-Term Incentive Plan (filed as Exhibit No. 10.1 to Amendment No. 3 to Form 10 of Spectra Energy Corp on December 6, 2006)
+10.14	Form of Non-Qualified Stock Option Agreement pursuant to the Spectra Energy Corp 2007 Long-Term Incentive Plan (filed as Exhibit No. 10.18 to Form 8-K of Spectra Energy Corp on August 3, 2007)
+10.15	Form of Phantom Stock Award Agreement pursuant to the Spectra Energy Corp 2007 Long-Term Incentive Plan (filed as Exhibit No. 10.19 to Form 8-K of Spectra Energy Corp on August 3, 2007)
10.16	$1,500,000,000 Credit Agreement, dated as of May 21, 2007, among Spectra Energy Capital, LLC, the banks listed therein, JPMorgan Chase Bank, N.A., as Administration Agent and Citibank, N.A., as Syndication Agent (filed as Exhibit No. 10.1 to Form 8-K of Spectra Energy Capital, LLC on May 22, 2007)
10.17	Twelfth Supplemental Indenture, dated December 14, 2007, among Spectra Energy Capital, LLC, Spectra Energy Corp and The Bank of New York (filed as Exhibit No. 10.1 to Form 8-K of Spectra Energy Corp on December 20, 2007)
*12.1	Computation of Ratio of Earnings to Fixed Charges.
*21.1	Subsidiaries of the Registrant.
*23.1	Consent of Independent Registered Public Accounting Firm.
*23.2	Consent of Independent Registered Public Accounting Firm.
*24.1	Power of Attorney

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Exhibit No.	Exhibit Description
*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.

* Filed herewith.
\+ Denotes management contract or compensatory plan or arrangement.