Spectra Energy Corp.
Form 10-K
February 25, 2010

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, 2009 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 whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). 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 June 30, 2009: $10,900,000,000

Number of shares of Common Stock, $0.001 par value, outstanding at February 12, 2010: 647,483,298

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the proxy statement for the 2010 Annual Meeting of Shareholders are incorporated by reference in Part III.

SPECTRA ENERGY CORP

FORM 10-K FOR THE YEAR ENDED

DECEMBER 31, 2009

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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, plan, project, predict, will, potential, forecast, and similar expressions. Forward-looking statements involve risks and uncertainties that may cause actual results to be materially different from the results predicted. Factors that could cause actual results to differ materially from those indicated in any forward-looking statement include, but are not limited to:

state, federal and foreign legislative and regulatory initiatives 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, which can affect the long-term demand for natural gas and related services;

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 market and economic conditions;

increases in the cost of goods and services required to complete capital projects;

declines in the market prices of equity and debt securities and resulting funding requirements for defined benefit pension plans;

growth in opportunities, including the timing and success of efforts to develop U.S. and Canadian 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.

PART I

Item 1. Business.

The terms we, our, us, and Spectra Energy as used in this report refer collectively to Spectra Energy Corp and its subsidiaries unless the context suggests otherwise. These terms are used for convenience only and are not intended as a precise description of any separate legal entity within Spectra Energy.

General

Spectra Energy Corp, through its subsidiaries and equity affiliates, 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, we and our predecessor companies have developed critically important pipelines and related energy infrastructure connecting natural gas supply sources to premium markets. We operate in three key areas of the natural gas industry: gathering and processing, transmission and storage, and distribution. Based in Houston, Texas, we provide 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. We also provide natural gas sales and distribution services to retail customers in Ontario, and natural gas gathering and processing services to customers in western Canada. We also have 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. Our internet website is *http://www.spectraenergy.com*.

Our natural gas pipeline systems consist of approximately 19,100 miles of transmission pipelines. Our proportional throughput for our pipelines totaled 3,987 trillion British thermal units (TBtu) in 2009, compared to 3,733 TBtu in 2008 and 3,642 TBtu in 2007. These amounts include throughput on wholly owned U.S. and Canadian pipelines and our proportional share of throughput on pipelines that are not wholly owned. Our storage facilities provide approximately 285 billion cubic feet (Bcf) of storage capacity in the United States and Canada.

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 us and all of our outstanding common stock was distributed to Duke Energy s shareholders.

Businesses

We manage our business in four reportable segments: U.S. Transmission, Distribution, Western Canada Transmission & Processing, and Field Services. The remainder of our 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 our businesses. For financial information on our business segments, see Part II, Item 8. Financial Statements and Supplementary Data, Note 4 of Notes to Consolidated Financial Statements.

U.S. TRANSMISSION

Our U.S. Transmission business provides transportation and storage of natural gas for customers in various regions of the northeastern and southeastern United States and the Maritime Provinces in Canada. Our U.S. pipeline systems consist of more than 14,300 miles of transmission pipelines with seven primary transmission systems: Texas Eastern Transmission, LP (Texas Eastern), Algonquin Gas Transmission, LLC (Algonquin), East Tennessee Natural Gas, LLC (East Tennessee), Maritimes & Northeast Pipeline, L.L.C. and Maritimes & Northeast Pipeline Limited Partnership (collectively, Maritimes & Northeast Pipeline), Ozark Gas Transmission, L.L.C. (Ozark Gas Transmission), Gulfstream Natural Gas System, LLC (Gulfstream) and Southeast Supply Header, LLC (SESH). The pipeline systems in our U.S. Transmission business receive natural gas from major North American producing regions for delivery to their respective markets. U.S. Transmission s proportional throughput for its pipelines totaled 2,574 TBtu in 2009, compared to 2,218 TBtu in 2008 and 2,202 TBtu in 2007. This includes throughput on wholly owned pipelines and our 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 services are provided on a short-term or seasonal basis.

U.S. Transmission provides storage services through Saltville Gas Storage Company L.L.C. (Saltville), Market Hub Partners Holding s (Market Hub s) Moss Bluff and Egan storage facilities, Steckman Ridge, LP (Steckman Ridge) and Texas Eastern s facilities. Gathering services are provided through Ozark Gas Gathering, L.L.C (Ozark Gas Gathering). 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. FERC is the U.S. agency that regulates the transportation of natural gas in interstate commerce.

In July 2007, we completed our initial public offering (IPO) of Spectra Energy Partners, LP (Spectra Energy Partners), a newly formed, natural gas infrastructure master limited partnership which is part of the U.S. Transmission segment. Subsequent to an additional drop-down of assets into Spectra Energy Partners in 2008 and the acquisition of NOARK Pipeline System, Limited Partnership (NOARK) in 2009, we currently retain a 74% equity interest in Spectra Energy Partners, which owns 100% of East Tennessee, 100% of Saltville, 100% of Ozark Gas Gathering and Ozark Gas Transmission, 50% of Market Hub and a 24.5% interest in Gulfstream. Spectra Energy retained a 50% direct ownership interest in Market Hub and a 25.5% direct ownership interest in Gulfstream. Spectra Energy Partners is a separate, publicly traded entity which trades on the New York Stock Exchange under the symbol SEP.

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. 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 74 Bcf.

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 seven 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 1,510 miles of pipeline in Tennessee, Georgia, North Carolina and Virginia, with 21 compressor stations. East Tennessee has a liquefied natural gas (LNG, natural gas that has been converted to liquid form) storage facility in Tennessee with a total working capacity of 1 Bcf. East Tennessee also connects to the Saltville storage facilities in Virginia that have a working gas capacity of approximately 5 Bcf.

We have an effective 74% ownership interest in East Tennessee through our ownership of Spectra Energy Partners.

Maritimes & Northeast Pipeline

Maritimes & Northeast Pipeline s gas transmission system is operated through Maritimes & Northeast Pipeline Limited Partnership (M&N LP), the Canadian portion of this system, and Maritimes & Northeast Pipeline, L.L.C. (M&N LLC), the U.S. portion. We have 78% ownership interests in both segments of the system and affiliates of Exxon Mobil Corporation and Emera, Inc. have the remaining interests. The Maritimes & Northeast Pipeline transmission system consists of approximately 900 miles of pipeline originating from landfall of the producing fields in Nova Scotia through New Brunswick, Maine, New Hampshire and Massachusetts, connecting to Algonquin in Beverly, Massachusetts. There are seven compressor stations on the system.

Ozark

We have an effective 74% interest in Ozark Gas Transmission and Ozark Gas Gathering, which was acquired by Spectra Energy Partners in May 2009. Ozark Gas Transmission consists of a 565-mile interstate natural gas pipeline system extending from southeastern Oklahoma through Arkansas to southeastern Missouri. Ozark Gas Gathering consists of a 365-mile gathering system that primarily serves Arkoma basin producers in eastern Oklahoma.

Gulfstream

We have an effective 44% investment in Gulfstream, a 745-mile interstate natural gas pipeline system operated jointly by us and The Williams Companies, Inc. Gulfstream transports natural gas from Mississippi, Alabama, Louisiana and Texas, crossing the Gulf of Mexico to markets in central and southern Florida. Gulfstream has three compressor stations. Gulfstream is owned 25.5% by Spectra Energy, 24.5% by Spectra Energy Partners and 50% by affiliates of The Williams Companies, Inc. Our investment in Gulfstream is accounted for under the equity method of accounting.

SESH

We have a 50% investment in SESH, a 274-mile interstate natural gas pipeline system with three mainline compressor stations owned and operated jointly by us and CenterPoint Energy, Inc. SESH, which began operations in September 2008, extends from the Perryville Hub in northeastern Louisiana where the emerging shale gas production of eastern Texas, northern Louisiana and Arkansas along with conventional production, is reached from five major interconnections. SESH extends to Alabama, interconnecting with 14 major north-south pipelines and three high deliverability storage facilities. Our investment in SESH is accounted for under the equity method of accounting.

Market Hub

We have an effective 87% ownership interest in Market Hub, which owns and operates two natural gas storage facilities, Moss Bluff and Egan, with a total storage capacity of approximately 43 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 four storage caverns located in south central Louisiana and has access to seven pipeline systems including the Texas Eastern system. Market Hub is a general partnership in which Spectra Energy and Spectra Energy Partners each have a 50% interest.

Saltville

We have an effective 74% ownership interest in Saltville through our ownership of Spectra Energy Partners. Saltville owns and operates natural gas storage facilities in Virginia with a total storage capacity of approximately 5 Bcf. The storage facilities interconnect with East Tennessee s system. This salt cavern facility offers high deliverability capabilities and is strategically located near markets in Tennessee, Virginia and North Carolina.

Steckman Ridge

We have a 50% investment in Steckman Ridge, a depleted reservoir storage facility located in south central Pennsylvania that has a total storage capacity of 12 Bcf and interconnects with Texas Eastern. Steckman Ridge, which began operations in April 2009, is operated by us and owned 50% by NJR Steckman Ridge Storage Company. Our investment in Steckman Ridge is accounted for under the equity method of accounting.

Competition

Our U.S. Transmission transportation and storage businesses compete with similar facilities that serve our 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 we transport in our transmission business competes with other forms of energy available to our 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, long-term economic conditions, conservation, legislation, governmental regulations, the ability to convert to alternative fuels, weather and other factors.

Customers and Contracts

In general, our U.S. Transmission pipelines provide transportation and storage services to local distribution companies (LDCs, companies that obtain a major portion of their revenues from retail distribution systems for the delivery of natural gas for ultimate consumption), electric power generators, exploration and production companies, and industrial and commercial customers, as well as energy marketers. Transportation and storage services are generally 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 our storage facilities plus a small variable component that is based on volumes transported to recover variable costs.

We also provide interruptible transportation and storage services where customers can use capacity if it is available at the time of the request. Interruptible revenues depend on the amount of volumes transported or stored and the associated market rates for this interruptible service. New projects placed into service may initially have higher levels of interruptible services at inception. Storage operations also provide a variety of other value-added services including natural gas parking, loaning and balancing services to meet our customers needs.

DISTRIBUTION

We provide distribution services in Canada through our 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 37,300 miles of distribution main and service pipelines. Distribution pipelines carry or control the supply of natural gas from the point of local supply to customers. Union Gas underground natural gas storage facilities have a working capacity of approximately 156 Bcf in 23 underground facilities located in depleted gas fields. Its transmission system consists of approximately 3,000 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 energy market participants. 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.

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. However, 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, economic conditions, 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 involving, among other things, phase-out of the sharing with customers of margins on Union Gas long-term storage transactions. This phase-out will occur over a four-year period that began in 2008, with the share accruing to Union Gas increasing ratably over that period. As a result of its finding that the market for storage services is competitive, the OEB does 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 competes 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 continue to be provided at cost-based rates and are not 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 west of Toronto, and across eastern Ontario from Port Hope to Cornwall. Union Gas serves approximately 1.3 million customers in a franchise area with more than 400 communities and a diversified commercial and industrial base.

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, including large 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 eight years, with the longest being almost 25 years.

WESTERN CANADA TRANSMISSION & PROCESSING

Our Western Canada Transmission & Processing business is comprised of the BC Pipeline and BC Field Services operations, and the natural gas liquids (NGLs) marketing and Canadian Midstream operations.

BC Pipeline and BC 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 BC, Alberta and the U.S. Pacific Northwest. BC Pipeline has approximately 1,800 miles of transmission pipeline in BC and Alberta, as well as 18 mainline compressor stations. Throughput for the BC Pipeline totaled 604 TBtu in 2009, compared to 615 TBtu in 2008 and 596 TBtu in 2007.

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 by the producers. NGLs are liquid hydrocarbons extracted during the processing of natural gas. Principal commercial NGLs include butanes, propane, natural gasoline and ethane. The BC Field Services business includes five gas processing plants located in BC, 17 field compressor stations and approximately 1,500 miles of gathering pipelines.

The Canadian Midstream business provides similar gas gathering and processing services in BC and Alberta and consists of 11 natural gas processing plants and approximately 600 miles of gathering pipelines.

The Empress NGL 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 United States. 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 NGLs are loaded for shipping or transferred into product sales pipelines, two NGL storage facilities and an NGL marketing and gas supply business. The Empress extraction and 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 gathering, processing and transportation of natural gas and the extraction and marketing of NGL products. Western Canada Transmission & Processing 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, NGLs and other forms of energy, the level of business activity, long-term economic conditions, conservation, legislation, governmental regulations, the ability to convert to alternative fuels, weather and other factors affect the demand for natural gas in the areas we serve.

In addition to the fee for service pipeline and gathering and processing businesses, we compete 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, we must be competitive in the premium or fee we pay to natural gas shippers. We also compete with other NGL marketers in the various markets we serve.

Customers & Contracts

BC Pipeline provides: (i) transportation services from the outlet of natural gas processing plants primarily in northeast BC to LDCs, end-use industrial and commercial customers, marketers, and exploration and production companies requiring transportation services to the nearest natural gas trading hub; and (ii) transportation services primarily to downstream markets in the Pacific Northwest (both United States and Canada). 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. BC Pipeline also provides interruptible transportation services where customers can use capacity if it is available at the time of request. Payments under these services are based on volumes transported.

The BC Field Services and Canadian Midstream operations in western Canada provide raw natural gas gathering and processing services to exploration and production companies under agreements which are primarily fee-for-service contracts which do not expose us to commodity-price risk. These operations provide both firm and interruptible services.

The NGL extraction operation at Empress, Alberta has capacity to produce approximately 63,000 barrels of NGLs per day (our share is approximately 58,000 barrels per day), comprised of approximately 50% ethane, 32% propane, 12% butanes and 6% condensate. At Empress, we extract and purchase NGLs from natural gas shippers on the TransCanada Pipeline system. In addition to paying shippers a negotiated extraction fee, we keep the shipper whole by returning an equivalent amount of natural gas for the NGLs that were extracted. After NGLs are extracted, we fractionate, or separate, the NGLs into ethane, propane, butanes and condensate, and sell these products into the marketplace. All ethane is sold to Alberta-based petrochemical companies. In addition to paying for natural gas shrinkage, the ethane buyers pay us a negotiated cost-of-service price or a negotiated fixed price. We sell the remaining products propane, butane and condensate at market prices and are exposed to the difference between the selling prices and the shrinkage makeup price of natural gas plus the extraction premium and operating costs. The majority of propane is sold to propane retailers. 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 we can obtain for these products are affected by numerous factors including competition, weather, transportation costs and supply and demand factors.

FIELD SERVICES

Field Services consists of our 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 26 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 nine major natural gas producing regions: Mid-Continent, Rocky Mountain, East Texas-North Louisiana, Barnett Shale, Gulf Coast, South Texas, Central Texas, Antrim Shale and Permian Basin. DCP Midstream owns or operates approximately 60,000 miles of gathering and transmission pipeline, with approximately 36,000 active receipt points.

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 operates 58 natural gas processing plants.

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.

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 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 near Beaumont, Texas 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 decreased approximately 42% and 38%, respectively, in 2009 compared to 2008. 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.

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 processors, 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 2009, sales to ConocoPhillips and Chevron Phillips Chemical Company LLC, combined, represented approximately 25% 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. Of the gas that is gathered and processed, more than 70% of volumes are under percentage-of-proceeds contracts.

- *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

We purchase 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.

We operate a North American supply chain management network with employees dedicated to this function in the United States and Canada. Our supply chain management group uses economies-of-scale to maximize the efficiency of supply networks where applicable. DCP Midstream performs its own supply chain management function.

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 our 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.

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.

Our U.S. Transmission and DCP Midstream operations are subject to the jurisdiction of the Environmental Protection Agency (EPA) and various other federal, state and local environmental agencies. See Environmental Matters for a discussion of environmental regulation. Our U.S. interstate natural gas pipelines and certain of DCP Midstream s gathering and transmission pipelines are also subject to the regulations of the U.S. Department of Transportation 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. Our 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 Canadian 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 of DCP Midstream are not subject to FERC regulation.

Environmental Matters

We are subject to various 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 us include, but are not limited to:

The Clean Air Act (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. Our natural gas processing, transmission and storage assets are considered sources of air emissions and are thereby subject to the CAA. Owners and/or operators of air emission sources, such as us, 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 (Clean Water 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 we are primarily a natural gas business, OPA affects our business primarily because of the presence of liquid hydrocarbons (condensate) in our offshore pipelines.

The Comprehensive Environmental Response, Compensation and Liability Act (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 our operations, we have disposed of waste at many different sites and have CERCLA liabilities at some properties we own.

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 our business, we generate 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 historical use of lubricating oils containing PCBs, the internal surfaces of some of our 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 site approvals. Many of our capital projects require federal agency review, and therefore the environmental effect of proposed projects is a factor in determining whether we 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 our facilities and operations in those provinces.

The Canadian Environmental Protection Act, pursuant to which, among other things, regulations require reporting of greenhouse gas (GHG) emissions from our operations in Canada. Additional regulations to be promulgated under the Act may require the reduction of GHGs, nitrogen oxides, sulphur oxides, volatile organic compounds and particulate matter.

The Alberta Climate Change and Emissions Management Act, which, pursuant to regulations that came into effect in 2007, requires certain facilities to meet reductions in emission intensity starting in 2007. The Act was applicable to our Empress facility in Alberta beginning in 2008.

For more information on environmental matters, including possible liability and capital costs, see Item 8. Financial Statements and Supplementary Data, Notes 5 and 17 of Notes to Consolidated Financial Statements.

Except to the extent discussed in Notes 5 and 17, compliance with international, federal, state and local provisions regulating the discharge of materials into the environment, or otherwise protecting the environment, is incorporated into the routine cost structure of our various business units and is not expected to have a material adverse effect on our competitive position or consolidated results of operations, financial position or cash flows.

Geographic Regions

For a discussion of our 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 19 of Notes to Consolidated Financial Statements.

Employees

We had approximately 5,400 employees as of December 31, 2009, including approximately 3,500 employees outside of the United States, all in Canada. In addition, DCP Midstream employed approximately 2,700 employees as of such date. Approximately 1,500 of our employees, all of whom are located in Canada, are subject to collective bargaining agreements governing their employment with us. Approximately 20% of those employees are covered under agreements that have expired or will expire by December 31, 2010.

Executive and Other Officers

The following table sets forth information regarding our executive and other officers.

Name	Age	Position
Gregory L. Ebel	45	President and Chief Executive Officer, Director
J. Patrick Reddy	57	Chief Financial Officer
Dorothy M. Ables	52	Chief Administrative Officer
John R. Arensdorf	59	Chief Communications Officer
Alan N. Harris	56	Chief Development and Operations Officer
Reginald D. Hedgebeth	42	General Counsel
Allen C. Capps	39	Vice President and Treasurer
Sabra L. Harrington	47	Vice President and Controller

Gregory L. Ebel assumed his current position as President and Chief Executive Officer on January 1, 2009. He previously served as Group Executive and Chief Financial Officer from January 2007. Mr. Ebel served as President of Union Gas from January 2005 until January 2007. Prior to then, Mr. Ebel served as Vice President, Investor & Shareholder Relations of Duke Energy from November 2002 until January 2005. Mr. Ebel currently serves on the Board of Directors of DCP Midstream, LLC.

J. Patrick Reddy joined Spectra Energy in January 2009 as Chief Financial Officer. Mr. Reddy served as Senior Vice President and Chief Financial Officer at Atmos Energy Corporation from September 2000 to December 2008. Mr. Reddy currently serves on the Board of Directors of DCP Midstream, LLC.

Dorothy M. Ables assumed her current position as Chief Administrative Officer in November 2008. Prior to then, she served as Vice President of Audit Services and as Chief Ethics and Compliance Officer from January 2007; Vice President of Audit Services for Duke Energy Corporation from April 2006 to December 2006; and Vice President, Audit Services and Chief Compliance Officer for Duke Energy Corporation from February 2004 to March 2006.

John R. Arensdorf assumed his current position in November 2008. He previously served as Vice President, Investor Relations from January 2007. Prior to then, Mr. Arensdorf served as General Manager, Investor Relations at Duke Energy from April 2006 to December 2006 and as General Manager, Internal Controls from November 2004 to April 2006.

Alan N. Harris assumed his current position as Chief Development Officer and Chief Operations Officer in November 2008. He previously served as Group Executive and Chief Development Officer since January 2007. Prior to then, Mr. Harris served as Group Vice President and Chief Financial Officer of Duke Energy Gas Transmission from February 2004 to January 2007. Mr. Harris currently serves on the Board of Directors of DCP Midstream Partners, LP.

Reginald D. Hedgebeth assumed his current position as General Counsel in March 2009. He previously served as Senior Vice President, General Counsel and Secretary with Circuit City Stores, Inc. from July 2005 to March 2009 and in various roles, including Vice President-Legal, at The Home Depot, Inc. from February 1999 to June 2005.

Allen C. Capps joined Spectra Energy in December 2007 as Vice President and Treasurer. Prior to then, Mr. Capps served as Director of Finance of EPCO, Inc., a midstream energy company, from April 2006. Mr. Capps served as Interim Controller of TEPPCO Partners, LP, an energy logistics partnership, from June 2005 to April 2006 and as Director of Technical Accounting and Compliance from April 2004 until June 2005.

Sabra L. Harrington assumed her current position as Vice President and Controller in January 2007. Prior to then, she served as Vice President, Financial Strategy of Duke Energy Gas Transmission from February 2006 and as Vice President and Controller of Duke Energy Gas Transmission from August 2003 until February 2006.

Additional Information

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

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 adversely affect our operations and cash flows.

Our regulated businesses are generally economically stable and are not significantly affected in the short-term by changing commodity prices. However, all of our businesses can be negatively affected in the long term by sustained downturns in the economy or long-term conservation efforts, which could affect long-term demand and market prices for natural gas and NGLs, all of which are beyond our control and could impair the ability to meet long-term goals.

Most of our 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 our 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 result in the non-renewal of long-term contracts at the time of expiration. Lower demand for natural gas and lower prices for natural gas and NGLs could result from multiple factors that affect the markets where we operate, 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 our processing business due to lower throughput;
- capacity and transmission service into or out of our markets; and
- petrochemical demand for NGLs.

The lack of availability of natural gas resources may cause customers to seek alternative energy resources, which could materially adversely affect our revenues, earnings and cash flows.

Our 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 are accessible by our pipeline, gathering, processing and distribution assets. Lack of commercial quantities of natural gas available to these assets could cause customers to seek alternative energy resources, thereby reducing their reliance on our services, which in turn would materially adversely affect our revenues, earnings and cash flows.

Investments and projects located in Canada expose us to fluctuations in currency rates that may adversely affect our results of operations, cash flows and compliance with debt covenants.

We are exposed to foreign currency risk from investments and operations in Canada. An average 10% devaluation in the Canadian dollar exchange rate during 2009 would have resulted in an estimated net loss on the translation of local currency earnings of approximately $35 million on our Consolidated Statement of Operations. In addition, if a 10% devaluation had occurred on December 31, 2009, the Consolidated Balance Sheet would be negatively impacted by $518 million through a cumulative translation adjustment in Accumulated Other Comprehensive Income (AOCI). At December 31, 2009, one U.S. dollar translated into 1.05 Canadian dollars.

In addition, we maintain credit facilities that typically include financial covenants which limit the amount of debt that can be outstanding as a percentage of total capital for Spectra Energy or of a specific subsidiary. Failure to maintain these covenants could preclude us from issuing commercial paper or letters of credit or borrowing under our revolving credit facilities 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 business. Foreign currency fluctuations have a direct impact on our ability to maintain certain of these financial covenants.

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

We have 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. We are primarily exposed to market price fluctuations of NGL prices in our Field Services segment and to frac-spreads in the Empress operations in Canada. Since NGL prices have historically been correlated with crude oil prices, we disclose our NGL price sensitivities in terms of crude oil price changes. Based on a sensitivity analysis as of December 31, 2009, at our forecasted NGL-to-oil price relationships, a $10 per barrel move in oil prices would affect our annual pre-tax earnings by approximately $100 million in 2010 ($90 million from Field Services and $10 million from U.S. Transmission). Assuming crude oil prices average approximately $80 per barrel, each 1% change in the price relationship between NGLs and crude oil would change our annual pre-tax earnings by approximately $10 million. At crude oil prices above $80 per barrel, the impact of a 1% change in the NGL-to-oil price relationship would increase, and at crude oil prices below $80 per barrel, the impact of a 1% change in the NGL-to-oil price relationship would decrease.

With respect to the frac-spread risk related to Empress processing and NGL marketing activities in western Canada, as of December 31, 2009, 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 our pre-tax earnings by approximately $12 million on an annual basis in 2010.

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 our earnings could be significantly different than these estimates.

Our business is subject to extensive regulation that affects our operations and costs.

Our U.S. assets and operations are subject to regulation by various federal, state and local authorities, including regulation by the FERC and by various authorities under federal, state and local environmental laws. Our 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 our business, including, among other things, the ability to determine terms and rates for services provided by some of our 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 our business, earnings, financial condition and cash flows.

Execution of our capital projects subjects us to construction risks, increases in labor and material costs and other risks that may adversely affect our financial results.

A significant portion of our 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, operational and market 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;
- 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 our ability to acquire rights-of-way or land rights on a timely basis and on acceptable terms;
- the ability to construct projects within anticipated costs, including the risk of cost overruns resulting from inflation or increased costs of equipment, materials or labor, weather, geologic conditions or other factors beyond our control, that may be material; and
- general economic factors that affect the demand for natural gas infrastructure.

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 their expected investment return, which could adversely affect our results of operations, financial position or cash flows.

Gathering and processing, transmission and storage, and distribution activities involve numerous risks that may result in accidents or otherwise affect our operations.

There are a variety of hazards and operating risks inherent in natural gas gathering and processing, transmission and storage, and distribution 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. 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. We do not maintain insurance coverage against all of these risks and losses, and any insurance coverage we 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 our business, earnings, financial condition and cash flows.

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

We are subject to numerous environmental laws and regulations affecting many aspects of our 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 us 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 our operating assets. In addition, changes in environmental laws and regulations or the enactment of new environmental laws or regulations could result in a material increase in our cost of compliance with such laws and regulations. We may not be able to obtain or maintain from time to time all required environmental regulatory approvals for our operating assets or development projects. If there is a delay in obtaining any required environmental regulatory approvals, if we fail to obtain or comply with them or if environmental laws or regulations change or are administered in a more stringent manner, 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 adverse effect.

The enactment of future climate change legislation could result in increased operating costs and delays in obtaining necessary permits for our capital projects.

The current international climate framework, the United Nations-sponsored Kyoto Protocol, prescribes specific targets to reduce GHG emissions for developed countries for the 2008-2012 period. The Kyoto Protocol expires in 2012 and has not been signed by the United States. United Nations-sponsored international negotiations were held in Copenhagen, Denmark in December 2009 with the intent of defining a future agreement for 2012 and beyond. While the talks resulted in a non-binding political agreement, to date, a binding successor accord to the Kyoto Protocol has not been realized.

While Canada is a signatory to the Kyoto Protocol, the Canadian federal government has confirmed it will not achieve the targets within the timeframes specified. Instead, the government in 2008 outlined a regulatory framework mandating GHG reductions from large final emitters. Regulatory design details from the Government of Canada remain forthcoming. We expect a number of our assets and operations in Canada will be affected by pending federal climate change regulations. However, the materiality of any potential compliance costs is unknown at this time as the final form of the regulation and compliance options has yet to be determined by policymakers.

In the United States, climate change action is evolving at state, regional and federal levels. We expect that a number of our assets and operations in the United States could be affected by eventual mandatory GHG programs; however, the timing and specific policy objectives in many jurisdictions, including at the federal level, remain uncertain. In addition, a number of Canadian provinces and U.S. states have joined regional greenhouse gas initiatives, and a number are developing their own programs that would mandate reductions in GHG emissions. We expect a number of our assets and operations could be affected either directly or indirectly by state or regional programs. However, as the key details of future GHG restrictions and compliance mechanisms remain undefined, the likely future effects on our business are highly uncertain.

The EPA has proposed the Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule in 2009 to address how GHG emissions would be regulated under the existing Clean Air Act. This proposed rulemaking has not yet been finalized. Regulation of GHG emissions under the Clean Air Act would subject our new capital projects to additional permitting requirements which may result in delays in completing such projects. In addition, several legislative proposals have been introduced and discussed in the U.S. Congress that would impose GHG emissions constraints, including H.R. 2454 the American Clean Energy and Security Act, which passed the House of Representatives in June 2009. To date, similar legislation has not been considered by the full U.S. Senate. Due to the speculative outlook regarding any U.S. federal and state policies and the uncertainty of the Canadian federal and provincial policies, we cannot estimate the potential effect of proposed GHG policies on our future consolidated results of operations, financial position or cash flows. However, such legislation could materially increase our operating costs, require material capital expenditures or create additional permitting, which could delay proposed construction projects.

We are involved in numerous legal proceedings, the outcome of which are uncertain, and resolutions adverse to us could negatively affect our results of operations, financial condition and cash flows.

We are subject to numerous legal proceedings. Litigation is subject to many uncertainties, and we cannot predict the outcome of individual matters with assurance. It is reasonably possible that the final resolution of some of the matters in which we are 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 our cash flows and results of operations.

We rely on access to short-term and long-term capital markets to finance capital requirements and support liquidity needs, and access to those markets can be adversely affected, particularly if we or our rated subsidiaries are unable to maintain an investment-grade credit rating, which could adversely affect our cash flows or restrict business.

Our 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, we rely on access to both short-term and long-term capital markets as a source of liquidity for capital requirements not satisfied by the cash flows from operations and to fund investments originally financed through debt. Our senior unsecured long-term debt is currently rated investment-grade by various rating agencies. If the rating agencies were to rate us or our rated subsidiaries below investment-grade, our borrowing costs would increase, perhaps significantly. In addition, we would likely be required to pay a higher interest rate in future financings, and our potential pool of investors and funding sources could decrease.

We maintain revolving credit facilities to provide back-up for commercial paper programs for borrowings 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 our short-term debt rating were to be below tier 2 (for example, A-2 for Standard and Poor s and P-2 for Moody s Investor Service), access to the commercial paper market could be significantly limited, although this would not affect our ability to draw under the credit facilities.

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

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

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

We are exposed to the credit risk of our customers.

We are exposed to the credit risk of our customers in the ordinary course of our business. Generally, our customers are rated investment-grade, are otherwise considered creditworthy or provide us security to satisfy credit concerns. Approximately 85% of our credit exposures for transportation, storage, and gathering and processing services are with customers who have an investment-grade rating or equivalent based on our evaluation. However, we cannot predict to what extent our business would be impacted by deteriorating conditions in the economy, including possible declines in our customers creditworthiness. As a result of future capital projects for which natural gas producers may be the primary customer, the percentage of our customers who are rated investment-grade may decline. While we monitor these situations carefully and take appropriate measures when deemed necessary, it is possible that customer payment defaults, if significant, could have a material adverse effect on our earnings and cash flows.

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

We have market-based rates for some of our storage operations and sell our 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 relative to demand, our approach to managing our market-based storage contract portfolio may not protect us 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, and the success of these claims could have a significant adverse effect on natural gas production and processing.

Certain aboriginal groups have claimed aboriginal and treaty rights over a substantial portion of public lands on which our 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 our facilities and of NGLs and other products transported in the associated pipelines. In addition, certain aboriginal groups in Ontario have claimed aboriginal and treaty rights in areas where Union Gas Dawn storage and transmission assets are located and also in areas where the Dawn-to-Trafalgar pipeline route is located. The existence of these claims could give rise to future uncertainty regarding land tenure depending upon their negotiated outcomes. We cannot predict the outcome of any of these claims or the effect they may ultimately have on our business and operations.

Protecting against potential terrorist activities requires significant capital expenditures and a successful terrorist attack could adversely affect our 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 ours, operating in any energy infrastructure industry that handles volatile gaseous and liquid hydrocarbons. The potential for terrorism has subjected our operations to increased risks that could have a material adverse effect on our business. In particular, we may experience increased capital and operating costs to implement increased security for our 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. We may be required to expend material amounts of capital to repair any facilities, the expenditure of which could adversely affect our cash flows and business.

Changes in the insurance markets attributable to terrorist attacks may make certain types of insurance more difficult for us to obtain. Moreover, the insurance that may be available to us may be significantly more expensive than our existing insurance coverage. Instability in the financial markets as a result of terrorism or war could also affect our ability to raise capital.

Poor investment performance of our pension plan holdings and other factors affecting pension plan costs could unfavorably affect our earnings, financial position and liquidity.

Our costs of providing defined benefit pension plans are dependent upon a number of factors, such as the rates of return on plan assets, discount rates used to measure pension liabilities, actuarial gains and losses, future government regulation and our contributions made to the plans. Without sustained growth in the pension plan investments over time to increase the value of our plan assets, and depending upon the other factors impacting our costs as listed above, we could experience net asset, expense and funding volatility. This volatility could have a material effect on our earnings and cash flows.

Item 1B. Unresolved Staff Comments.

None.

Item 2. Properties.

At December 31, 2009, we had over 100 primary facilities located in the United States and Canada. We generally own sites associated with our major pipeline facilities, such as compressor stations. However, we generally operate our transmission facilities transmission and distribution pipelines using rights of way pursuant to easements to install and operate pipelines, but we do not own the land. Except as described in Part II, Item 8. Financial Statements and Supplementary Data, Note 14 of Notes to Consolidated Financial Statements, none of our properties were secured by mortgages or other material security interests at December 31, 2009.

Our corporate headquarters are located at 5400 Westheimer Court, Houston, Texas 77056, which is a leased facility. The lease expires in April 2018.We also maintain offices in, among other places, Calgary, Alberta; Vancouver, British Columbia; Chatham, Ontario; Waltham, Massachusetts; Tampa, Florida; Halifax, Nova Scotia; Toronto, Ontario; and Nashville, Tennessee. For a description of our material properties, see Item 1. Business.

Item 3. Legal Proceedings.

For information regarding legal proceedings, including regulatory and environmental matters, see Notes 5 and 17 of Notes to Consolidated Financial Statements.

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

None.

PART II

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

Our common stock is traded on the New York Stock Exchange under the symbol SE. As of February 12, 2010, there were approximately 148,000 holders of record of our common stock and approximately 450,000 beneficial owners.

Common Stock Data by Quarter

	Dividends Per	Stock Price Range(a)	
2009	**Common Share**	**High**	**Low**
First Quarter	$ 0.25	$ 17.47	$ 11.21
Second Quarter	0.25	17.61	13.75
Third Quarter	0.25	19.73	15.81
Fourth Quarter	0.25	20.78	18.26
2008			
First Quarter	0.23	26.26	21.41
Second Quarter	0.23	29.18	22.67
Third Quarter	0.25	29.13	22.00
Fourth Quarter	0.25	23.77	13.36

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

Stock Performance Graph

The following graph reflects the comparative changes in the value from January 3, 2007, the first trading day of Spectra Energy common stock on the New York Stock Exchange, through December 31, 2009 of $100 invested in (1) Spectra Energy s common stock, (2) the Standard & Poor s 500 Stock Index, and (3) the Standard & Poor s 500 Oil & Gas Storage & Transportation Index. The amounts included in the table were calculated assuming the reinvestment of dividends at the time dividends were paid.

	January 3,	December 31,		
	2007	2007	2008	2009
Spectra Energy Corp	$ 100.00	$ 93.47	$ 59.54	$ 82.34
S&P 500 Stock Index	100.00	105.60	66.53	84.14
S&P 500 Storage & Transportation Index	100.00	114.30	56.81	79.38

Dividends

We currently anticipate an average dividend payout ratio over time of approximately 60-65% of our estimated annual net income from controlling interests per share of common stock and expect to continue our policy of paying regular cash dividends. The actual payout ratio, however, may vary from year to year depending on earnings levels. The declaration and payment of dividends are subject to the sole discretion of our Board of Directors and depends upon many factors, including the financial condition, earnings and capital requirements of our operating subsidiaries, covenants associated with certain debt obligations, legal requirements, regulatory constraints and other factors deemed relevant by our Board of Directors.

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 Statements and Supplementary 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 our predecessor entity 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 we had operated as a separate, stand-alone entity for periods presented prior to 2007.

	2009	2008	2007	2006(a)	2005(b)
	(dollars in millions, except per-share amounts)				
Statements of Operations					
Operating revenues	$ 4,552	$ 5,074	$ 4,704	$ 4,501	$ 9,412
Operating income	1,475	1,480	1,426	1,234	1,844
Income from continuing operations(c)	918	1,192	1,002	972	1,914
Net income controlling interests	848	1,129	957	1,244	674
Ratio of Earnings to Fixed Charges	3.1	3.6	3.1	3.0	4.3
Common Stock Data					
Earnings per share from continuing operations					
Basic	$ 1.31	$ 1.82	$ 1.48	n/a	n/a
Diluted	1.31	1.81	1.48	n/a	n/a
Earnings per share					
Basic	1.32	1.82	1.51	n/a	n/a
Diluted	1.32	1.81	1.51	n/a	n/a
Dividends per share	1.00	0.96	0.88	n/a	n/a

	December 31,				
	2009	2008	2007	2006	2005
	(in millions)				
Balance Sheet					
Total assets	$ 24,079	$ 21,924	$ 22,970	$ 20,345	$ 35,056
Long-term debt including capital leases, less current maturities	8,947	8,290	8,345	7,726	8,790

(a) Significant transactions reflected in 2006 results include: the transfer of certain businesses to Duke Energy in December 2006 in preparation of our spin-off from Duke Energy, with total assets of approximately $5.1 billion and operating revenues of $1.0 billion; our indirect transfer of Duke Energy North America (DENA)

Midwestern assets to Duke Energy Ohio, Inc., with approximately $1.6 billion of assets and operating revenues of $788 million; a $250 million gain associated with the creation of the Crescent Resources joint venture; and the subsequent deconsolidation of Crescent Resources.

(b) Significant transactions reflected in 2005 results include pre-tax losses of approximately $1.1 billion related to sales of DENA s assets and contracts outside the Midwestern United States; the deconsolidation of DCP Midstream effective July 1, 2005; and the DCP Midstream sale of TEPPCO.

(c) Includes noncontrolling interests of $75 million, $65 million, $70 million, $61 million and $529 million for the years 2009 through 2005, respectively.

n/a Indicates not applicable.

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 Item 8. Financial Statements and Supplementary Data.

EXECUTIVE OVERVIEW

Throughout 2009, we continued to successfully execute on the strategies and objectives we outlined for our shareholders. These included exceeding our earnings objectives, the successful execution on capital expansion plans that underlie our growth objectives, and maintaining a strong balance sheet. In addition, we executed contracts in 2009 that support substantial continued growth of our market positions.

During 2009, our fee-based businesses at U.S. Transmission, Distribution and Western Canada Transmission & Processing performed well by meeting the needs of our customers and generated increased earnings and cash flows as a result of successful expansion projects placed into service. Commodity prices negatively affected the comparison to 2008 for our Field Services segment and the Empress operations at Western Canada Transmission & Processing.

We reported net income from controlling interests of $848 million, and $1.32 of diluted earnings per share for 2009 compared to net income from controlling interests of $1,129 million, and $1.81 of diluted earnings per share for 2008. The decrease in 2009 primarily reflects lower earnings from Field Services and Western Canada Transmission & Processing, as a result of the lower NGL prices associated with lower crude oil prices in 2009. Crude oil averaged $62 per barrel for 2009 versus $100 per barrel in 2008. The decrease in earnings in 2009 was partially offset by the recognition of a $135 million deferred gain ($85 million after-tax) in 2009 associated with partnership units previously issued by DCP Midstream Partners, LP (DCP Partners), DCP Midstream s master limited partnership, as well as earnings from growth projects.

We reported $1.0 billion of capital and investment expenditures for 2009, including approximately $500 million of expansion capital expenditures. This does not include the $295 million acquisition of NOARK. We successfully completed our 2009 expansion plans, with returns on these projects slightly above our targeted 10-12% return on capital employed range. Return on capital employed as it relates to expansion projects is calculated by us as incremental earnings before interest and taxes generated by a project divided by the total cost of the project. We plan to increase our expansion capital spending to a total of approximately $5.0 billion from 2010 through 2014, with approximately $1.0 billion planned for 2010, as we continue to pursue opportunities around new natural gas supply volumes in Western Canada and the Appalachian and Southeast regions of the United States.

We issued approximately $1.0 billion of new long-term debt in 2009, the need for which was driven by our 2009 and 2010 capital expansion plans, as well as refinancing of project debt. As of December 31, 2009, we continue to have ongoing access to approximately $2.3 billion available under our credit facilities and expect to continue to utilize commercial paper and revolving lines of credit, as needed, to fund liquidity needs throughout

2010. Financing activities in 2010 will include the refinancing of debt maturities of approximately $800 million and the issuance of commercial paper under our revolving credit facilities. We may also access the capital markets for other long-term financing if conditions are favorable.

In February 2009, in order to enhance our capital structure, we issued 32.2 million shares of our common stock and received net proceeds of $448 million.

In May 2009, Spectra Energy Partners acquired all of the ownership interests of NOARK from Atlas Pipeline Partners, L.P. (Atlas) for approximately $295 million in cash. In the second quarter of 2009, Spectra Energy Partners issued 9.8 million of its common units to the public, representing limited partner interests, and 0.2 million general partner units to Spectra Energy, in connection with the refinancing of the purchase of NOARK, resulting in net proceeds of $212 million and a reduction of our ownership interest in Spectra Energy Partners from 84% to 74%. See Notes 2 and 3 of Notes to Consolidated Financial Statements for further discussion.

Our Strategy. Our primary business objective is to create superior and sustainable value for our investors, customers, employees and communities by providing natural gas gathering, processing, transmission, storage and distribution services. We intend to accomplish this objective by executing the following overall business strategies, which remain consistent with our 2009 strategies:

- Deliver on 2010 financial commitments.
- Develop new opportunities and projects that add long-term shareholder value and meet customers needs.
- Effectively execute on our 2010 expansion plans.
- Enhance and solidify our profile and position as an advisor and partner of choice.
- Build on our high-performance culture by focusing on safety and employee engagement.

We know we are successful when we are the supplier of choice for our customers, the employer of choice for individuals, the advisor of choice on policy and regulation for governments and regulators, the partner of choice for our communities, and the investment opportunity of choice for investors.

2009 Financial Results. We reported net income from controlling interests of $848 million in 2009 compared to net income from controlling interests of $1,129 million in 2008. The decrease in net income from controlling interests primarily reflects lower earnings from Field Services and Western Canada Transmission & Processing, partially offset by the recognition of a $135 million deferred gain ($85 million after-tax) in 2009 associated with partnership units previously issued by DCP Partners, as well as earnings from growth projects. Highlights for 2009 include the following:

- U.S. Transmission s results reflect higher earnings from expansion projects placed into service late in 2008 and in 2009, lower project development costs in 2009 and an impairment of the Islander East project in 2008, partially offset by lower gas processing revenues in 2009, increased operating costs and a customer bankruptcy settlement in 2008,
- Distribution results reflect a weaker Canadian dollar, lower customer usage and higher expenses related to expansion projects, partially offset by higher storage and transportation revenues,
- Western Canada Transmission & Processing earnings decreased primarily as a result of lower NGL gross margins related to the Empress processing plant and a weaker Canadian dollar, partially offset by higher gathering and processing revenues and lower plant fuel and electricity costs, and

Field Services earnings reflect lower NGL and natural gas prices, and lower gathering and processing margins, partially offset by the recognition of a deferred gain associated with partnership units previously issued by DCP Partners.

Significant Economic Factors For Our Business. Our regulated businesses are generally economically stable and are not significantly affected in the short-term by changing commodity prices. However, all of our businesses can be negatively affected in the long term by sustained downturns in the economy or long-term conservation efforts, which could affect long-term demand and market prices for natural gas and NGLs, all of which are beyond our control and could impair our ability to meet long-term goals.

Most of our 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 our 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 result in the non-renewal of long-term contracts at the time of expiration. Pipeline transportation and storage customers continue to renew most contracts as they expire. Processing revenues and the earnings and distributions from our Field Services segment are also affected by volumes of natural gas made available to our systems, which are primarily driven by levels of natural gas drilling activity. Current levels of interest remain strong for natural gas exploration and drilling in the areas that affect our Western Canada and Field Services segments, primarily driven by recent positive developments around unconventional gas reserves production in numerous locations within North America.

Our combined key markets the northeastern and the southeastern United States, the Pacific Northwest, British Columbia and Ontario 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 2019. 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 our growth strategies. Traditionally, supply to our markets has come from the Gulf Coast region, both onshore and offshore, as well as from fields in western and eastern Canada. The national supply profile is shifting to new sources of gas from basins in the Rockies, Mid-Continent, Appalachia, Texas and Louisiana. In addition, the natural gas supply outlook includes new LNG re-gasification facilities on the Gulf Coast and in the Northeast. 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 we serve. These supply shifts are shaping the growth strategies that we 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.

Our businesses in the United States 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 we cannot predict the future course of changes in the regulatory environment or the ultimate effect that any future changes will have on our businesses. Additionally, investments and projects located in Canada expose us to risks related to Canadian laws, taxes, economic conditions, fluctuations in currency rates, political conditions and policies of the Canadian government. From 2002 through 2009, the Canadian dollar strengthened significantly compared to the U.S. dollar, which favorably affected earnings and equity during these periods, except in the fourth quarter 2008 and the first quarter 2009 when the Canadian dollar weakened significantly in a very short period of time. Changes in this exchange rate or other of these factors are difficult to predict and may affect our future results and financial position.

Certain of our earnings are affected by fluctuations in commodity prices, especially the earnings of DCP Midstream and the Empress NGL operations in Canada. We evaluate, on an ongoing basis, the risks associated with commodity price volatility and currently do not have any plans to enter into hedge positions around these earnings.

Based on current projections, it is expected that our effective income tax rate on continuing operations will approximate 28 29% for 2010. Our overall effective tax rate largely depends on the proportion of earnings in the United States, subject to a 35% federal statutory tax rate, to the earnings of our Canadian operations, with an effective tax rate of approximately 21% that is driven by lower statutory rates and recognition of certain regulatory tax benefits.

As we execute on our strategic objectives, capital expansion projects will continue to be an important part of our growth plan. We currently anticipate capital and investment expenditures in 2010 of approximately $1.6 billion. We issued approximately $1.0 billion of new long-term debt in 2009, and financing activities in 2010 will include the refinancing of debt maturities of approximately $800 million and the issuance of commercial paper under our revolving credit facilities. We may also access capital markets for other long-term financing if conditions are favorable. An inability to access capital at competitive rates could adversely affect our ability to implement our strategy. Market disruptions or a downgrade in our credit ratings may increase the cost of borrowing or adversely affect our ability to access one or more sources of liquidity.

During the past few years, capital expansion projects have been exposed to cost pressures associated with the availability of skilled labor and the pricing of materials. Although certain costs have begun to decrease in the current economic conditions, there will be continual focus on project management activities to address these pressures as we move forward with planned expansion opportunities. Significant cost increases could negatively affect the returns ultimately earned on current and future expansions.

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

RESULTS OF OPERATIONS

	2009	2008 (in millions)	2007
Operating revenues	$ 4,552	$ 5,074	$ 4,704
Operating expenses	3,088	3,636	3,291
Gains on sales of other assets and other, net	11	42	13
Operating income	1,475	1,480	1,426
Other income and expenses	406	844	649
Interest expense	610	636	633
Earnings from continuing operations before income taxes	1,271	1,688	1,442
Income tax expense from continuing operations	353	496	440
Income from continuing operations	918	1,192	1,002
Income from discontinued operations, net of tax	5	2	25
Net income	923	1,194	1,027
Net income noncontrolling interests	75	65	70
Net income controlling interests	$ 848	$ 1,129	$ 957

2009 Compared to 2008

Operating Revenues. The $522 million, or 10%, decrease was driven primarily by:

lower NGL prices and sales volumes associated with the Empress operations at Western Canada Transmission & Processing,

the effects of a weaker Canadian dollar on revenues at Western Canada Transmission & Processing and Distribution, and

lower natural gas prices passed through to customers without a mark-up at Distribution, partially offset by higher earnings from expansion projects placed into service late in 2008 and in 2009 at U.S. Transmission.

Operating Expenses. The $548 million, or 15%, decrease was driven primarily by:

- lower prices and volumes of natural gas purchased for the Empress facility at Western Canada Transmission & Processing,
- the effects of a weaker Canadian dollar at Western Canada Transmission & Processing and Distribution,
- lower natural gas prices passed through to customers without a mark-up at Distribution, and
- lower project development costs at U.S. Transmission.

Gain on Sales of Other Assets and Other, net. The $31 million decrease was primarily due to a 2008 customer bankruptcy settlement at U.S. Transmission.

Operating Income. The $5 million decrease was primarily due to lower NGL margins associated with the Empress operations at Western Canada Transmission & Processing, a weaker Canadian dollar and a 2008 customer bankruptcy settlement at U.S. Transmission, mostly offset by higher earnings from expansion projects placed into service late in 2008 and in 2009, and lower project development costs at U.S. Transmission.

Other Income and Expenses. The $438 million decrease was attributable to lower equity in earnings from Field Services, primarily reflecting lower commodity prices in 2009 compared to 2008, partially offset by a gain recognized in the first quarter of 2009 associated with partnership units previously issued by DCP Partners.

Interest Expense. The $26 million decrease reflects primarily the recognition of gains from the termination of fair value hedges, the effects of a weaker Canadian dollar, and lower balances and rates on commercial paper, partially offset by higher debt balances.

Income Tax Expense from Continuing Operations. The $143 million decrease was a result of lower earnings from continuing operations in 2009. The effective tax rate for income from continuing operations was 27.8% compared to 29.4% in 2008. The lower effective tax rate for 2009 was primarily due to proportionally higher income generated from our Canadian operations, which are subject to lower tax rates compared to our U.S. operations, and favorable tax settlements in 2009.

Net Income Noncontrolling Interests. The $10 million increase was driven by an increase in the noncontrolling interests ownership percentage due to the Spectra Energy Partners public sale of additional partner units in the second quarter of 2009 and higher earnings from Spectra Energy Partners and M&N LLC.

For a more detailed discussion of earnings drivers, see the segment discussions that follow.

2008 Compared to 2007

Operating Revenues. The $370 million, or 8%, increase was driven primarily by:

- higher NGL prices and volumes associated with the Empress operations,
- expansion projects placed in service in late 2007 and the fourth quarter of 2008 at U.S. Transmission, and
- growth in the number of customers, an increase in customer usage due to colder weather, and higher storage and transportation revenues primarily due to favorable market conditions and growth of the transmission system at Distribution.

Operating Expenses. The $345 million, or 10%, increase was driven primarily by:

higher prices and volumes of natural gas and NGLs purchased for the Empress facility, an increase in project development costs as a result of growth projects in 2008 and the capitalization of previously expensed costs on northeast expansions in 2007 and increased operating costs at U.S. Transmission, and

growth in the number of customers and an increase in customer usage at Distribution.

Gain on Sales of Other Assets and Other, net. The $29 million increase was primarily due to a 2008 customer bankruptcy settlement of $27 million.

Operating Income. The $54 million increase is primarily as a result of higher NGL margins from the Empress operations, a 2008 customer bankruptcy settlement and higher earnings from expansion projects, partially offset by higher project development costs charged to expense and higher operating costs.

Other Income and Expenses. The $195 million increase primarily represents higher equity in earnings from the Field Services segment, reflecting higher commodity prices in 2008 compared to 2007.

Interest Expense. The $3 million increase reflects the completion of our planned debt issuances in 2008, offset by lower balances and rates on commercial paper in 2008.

Income Tax Expense from Continuing Operations. The $56 million increase was a result of higher earnings from continuing operations. The effective tax rate for income from continuing operations was 29.4% compared to 30.5% for the same period in 2007. The lower effective tax rate for 2008 was primarily a result of reductions in Canadian and U.S. state tax rates.

Income from Discontinued Operations, net of tax. The $23 million decrease is driven by proceeds received from a litigation settlement in 2007. This decrease also reflects lower operating results of certain Western Canada Transmission & Processing natural gas gathering and processing facilities. In December 2008, we closed on the sale of our interests in these facilities.

Net Income Noncontrolling Interests. The $5 million decrease primarily reflects lower operating results of certain Western Canada Transmission & Processing natural gas gathering and processing facilities in 2008 compared to 2007 and the second quarter 2008 purchase of the units of the Spectra Energy Income Fund (the Income Fund) that were held by non-affiliated holders, partially offset by earnings from Spectra Energy Partners which was formed in July 2007. Prior to the acquisition of the units, the Income Fund indirectly held 54% of our consolidated Canadian Midstream operations and we held the remaining 46%.

For a more detailed discussion of earnings drivers, see the segment discussions that follow.

Segment Results

We evaluate segment performance based on earnings before interest and taxes (EBIT) from continuing operations less noncontrolling interests related to those earnings. On a segment basis, EBIT represents earnings from continuing operations (both operating and non-operating) before interest and taxes, net of noncontrolling interests related to those earnings. Cash, cash equivalents and investments are managed centrally, so the gains and losses on foreign currency remeasurement, and interest and dividend income on those balances, are excluded from the segments EBIT. We consider segment EBIT to be a good indicator of each segment s operating performance from its continuing operations, as it represents the results of our ownership interest in operations without regard to financing methods or capital structures.

U.S. Transmission provides transportation and storage of natural gas for customers in various regions of the northeastern 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.

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 us and 50% by ConocoPhillips. Field Services gathers raw natural gas through gathering systems located in nine major natural gas producing regions: Mid-Continent, Rocky Mountain, East Texas-North Louisiana, Barnett Shale, Gulf Coast, South Texas, Central Texas, Antrim Shale and Permian Basin.

Our segment EBIT may not be comparable to similarly titled measures of other companies because other companies may not calculate EBIT in the same manner. Segment EBIT is summarized in the following table and detailed discussions follow:

EBIT by Business Segment

	2009	2008	2007
		(in millions)	
U.S. Transmission	$ 894	$ 844	$ 894
Distribution	336	353	322
Western Canada Transmission & Processing	343	398	359
Field Services	296	716	533
Total reportable segment EBIT	1,869	2,311	2,108
Other	(74)	(78)	(112)
Total reportable segment and other EBIT	1,795	2,233	1,996
Interest expense	610	636	633
Interest income and other(a)	86	91	79
Earnings from continuing operations before income taxes	$ 1,271	$ 1,688	$ 1,442

(a) Includes foreign currency transaction gains and losses and the add-back of noncontrolling interests related to segment EBIT. Noncontrolling interests as presented in the following segment-level discussions includes only noncontrolling interests related to EBIT of non-wholly owned subsidiaries. It does not include noncontrolling interests 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

	2009	2008	Increase (Decrease)	2007	Increase (Decrease)
		(in millions, except where noted)			
Operating revenues	$ 1,690	$ 1,600	$ 90	$ 1,540	$ 60
Operating expenses					
Operating, maintenance and other	577	595	(18)	473	122
Depreciation and amortization	246	232	14	217	15
Gains on sales of other assets and other, net	11	42	(31)	8	34
Operating income	878	815	63	858	(43)
Other income and expenses	91	86	5	85	1
Noncontrolling interests	75	57	18	49	8
EBIT	$ 894	$ 844	$ 50	$ 894	$ (50)

Proportional throughput, TBtu(a)	2,574	2,218	356	2,202	16

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

2009 Compared to 2008

Operating Revenues. The $90 million increase was driven primarily by:

- a $136 million increase from expansion projects placed into service late in 2008 and 2009,
- a $43 million increase in transportation and other revenues primarily from Ozark Gas Transmission acquired in May 2009, and
- a $14 million increase primarily in transportation and storage revenues from recoveries of fuel, electric power and other costs passed through to customers, partially offset by
- an $88 million decrease in processing revenues associated with pipeline operations, caused by lower prices and volumes,
- an $11 million decrease resulting from a weaker Canadian dollar at M&N LP, and
- a $9 million decrease in interruptible transportation revenue due to weather and other market conditions.

Operating, Maintenance and Other. The $18 million decrease was driven primarily by:

- an $82 million decrease in project development costs, reflecting a net benefit of $39 million in 2009 primarily due to a reimbursement of project development costs by customers and the capitalization of previously expensed costs on northeast expansions compared to expensed project development costs of $43 million in 2008, partially offset by
- a $17 million increase from expansion projects placed in service late in 2008 and in 2009,
- a $16 million increase from Ozark Gas Transmission,
- a $15 million increase in operating costs, including pipeline integrity costs, equipment repairs and maintenance costs, and software costs, and
- a $13 million increase in operating costs from higher fuel, electric power and other costs passed through to customers.

Depreciation and Amortization. The $14 million increase was primarily driven by expansion projects placed into service late in 2008 and in 2009.

Gains on Sales of Other Assets and Other, net. The $31 million decrease was driven by a customer bankruptcy settlement in June 2008.

Other Income and Expenses. The $5 million increase was primarily a result of an impairment of the Islander East project in 2008 and earnings from expansion projects on Gulfstream and SESH placed into service in late 2008, mostly offset by lower allowance for funds used during construction (AFUDC) equity associated with construction projects and from the discontinuance of rate regulated accounting treatment by SESH.

Noncontrolling Interests. The $18 million increase was driven by an increase in the noncontrolling interests ownership percentage resulting from the Spectra Energy Partners public sale of additional partner units in the second quarter of 2009 and higher earnings from Spectra Energy

Partners and M&N LLC.

EBIT. The $50 million increase was primarily due to higher earnings from expansion projects, lower project development costs in 2009 and an impairment of the Islander East project in 2008. These increases were partially offset by lower processing revenues, increased operating costs and a customer bankruptcy settlement in 2008.

2008 Compared to 2007

Operating Revenues. The $60 million increase was driven primarily by:

- a $69 million increase from expansion projects placed in service in late 2007 and the fourth quarter of 2008, partially offset by
- an $8 million decrease in processing revenues associated with pipeline operations, primarily from lower volumes, partially offset by higher prices.

Operating, Maintenance and Other. The $122 million increase was driven primarily by:

- a $60 million increase in project development costs, reflecting expensed project development costs of $43 million in 2008 and a net benefit of $17 million in 2007 due to the capitalization of previously expensed costs on northeast expansions during that period,
- a $39 million increase in operating costs including fuel, utilities, equipment repairs and software costs,
- a $12 million increase in ad valorem taxes primarily as a result of favorable property valuations in certain states and business expansion projects placed in service in late 2007, and
- a $12 million increase due to an impairment of Algonquin s Islander East project costs caused by adverse legal rulings and unfavorable economic conditions.

Depreciation and Amortization. The $15 million increase was primarily driven by expansion projects placed into service in late 2007.

Gains on Sales of Other Assets and Other, net. The $34 million increase primarily reflects a customer bankruptcy settlement in 2008.

Other Income and Expenses. The $1 million increase was primarily a result of higher equity income from unconsolidated affiliates attributable to the capitalization of interest on construction projects and lower project development costs charged to expense, both of which are primarily for the SESH project, offset by a $32 million impairment of the Islander East project.

Noncontrolling Interests. The $8 million increase was driven primarily by earnings from Spectra Energy Partners formed in July 2007.

EBIT. The $50 million decrease was primarily due to an impairment of the Islander East project caused by adverse legal rulings and unfavorable economic conditions, development costs charged to expense and increased operating costs. These decreases were partially offset by higher earnings from expansion projects and a gain on a customer bankruptcy settlement.

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. 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.

Future earnings growth will be dependent on the success of expansion plans in both the market and supply areas of the pipeline network, which includes, among other things, shale gas exploration and development areas, 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

	2009	2008	Increase (Decrease)	2007	Increase (Decrease)
	(in millions, except where noted)				
Operating revenues	$ 1,745	$ 1,991	$ (246)	$ 1,899	$ 92
Operating expenses					
Natural gas purchased	878	1,094	(216)	1,059	35
Operating, maintenance and other	358	372	(14)	361	11
Depreciation and amortization	172	175	(3)	162	13
Gains on sales of other assets and other, net				5	(5)
Operating income	337	350	(13)	322	28
Other income and expenses	(1)	3	(4)		3
EBIT	$ 336	$ 353	$ (17)	$ 322	$ 31
Number of customers, thousands	1,325	1,309	16	1,289	20
Heating degree days, Fahrenheit	7,435	7,491	(56)	7,070	421
Pipeline throughput, TBtu	809	900	(91)	844	56

2009 Compared to 2008

Operating Revenues. The $246 million decrease was driven primarily by:

- a $160 million decrease resulting from a weaker Canadian dollar,
- a $130 million decrease from lower natural gas prices passed through to customers without a mark-up,
- a $69 million decrease in customer usage of natural gas due to the impacts of the economic recession, and
- an $11 million decrease due to a 2009 settlement on 2008 earnings to be shared with customers, partially offset by
- a $56 million increase due to growth in the number of customers,
- a $40 million increase in storage and transportation revenues attributable to expansion of the storage system and an increase in short-term transportation services provided to customers,
- a $15 million increase resulting from a charge in 2008 due to an unfavorable decision from the OEB related to unregulated storage revenues, and
- a $9 million increase due to lower 2009 regulated earnings to be shared with customers.

Natural Gas Purchased. The $216 million decrease was driven primarily by:

- a $130 million decrease from lower natural gas prices passed through to customers without a mark-up,
- a $91 million decrease resulting from a weaker Canadian dollar, and
- a $56 million decrease in customer usage of natural gas due to the impacts of the economic recession, partially offset by
- a $48 million increase due to growth in the number of customers, and
- a $6 million increase in fuel used in operations.

Operating, Maintenance and Other. The $14 million decrease was driven primarily by:

- a $24 million decrease resulting from a weaker Canadian dollar, partially offset by
- a $9 million increase as a result of expansion projects.

Depreciation and Amortization. The $3 million decrease was driven primarily by:

- a $12 million decrease resulting from a weaker Canadian dollar, mostly offset by
- a $9 million increase as a result of expansion projects.

EBIT. The $17 million decrease was primarily a result of a weaker Canadian dollar, lower customer usage and higher expenses related to expansion projects. These decreases were partially offset by higher storage and transportation revenues and growth in the number of customers.

2008 Compared to 2007

Operating Revenues. The $92 million increase was driven primarily by:

- a $43 million increase due to growth in the number of customers primarily as a result of increased residential customer attachments,
- a $39 million increase in storage and transportation revenues primarily due to favorable market conditions and growth of the transmission system,
- a $33 million increase in customer usage of natural gas due to colder weather, and
- a $14 million increase resulting from a stronger Canadian dollar, partially offset by
- a $14 million decrease as a result of earnings sharing under the incentive regulation framework implemented in 2008,
- a $15 million decrease due to an unfavorable decision from the OEB on unregulated storage revenues in 2008, and
- an $8 million decrease from lower natural gas prices passed through to customers without a mark-up.

Natural Gas Purchased. The $35 million increase was driven primarily by:

- a $40 million increase due to growth in the number of customers primarily as a result of increased residential customer attachments, and
- a $28 million increase in customer usage of natural gas due to colder weather, partially offset by
- a $23 million decrease related to fuel used in operations, and
- an $8 million decrease related to lower natural gas prices passed through to customers without a mark-up.

Operating, Maintenance and Other. The $11 million increase was driven primarily by higher payroll and contractor costs partially offset by lower pension costs.

Depreciation and Amortization. The $13 million increase was due to a higher asset base resulting primarily from completion of Phase II of the Dawn-Trafalgar expansion of the transmission system.

Gains on Sales of Other Assets and Other, net. The $5 million decrease was due to a gain on the sale of land in 2007.

EBIT. The $31 million increase was primarily attributable to higher storage and transportation revenues and less fuel used in operations, partially offset by earnings sharing under the incentive regulation framework implemented in 2008.

Matters Affecting Future Distribution Results

We expect that the long-term demand for natural gas in North America will continue to grow. However, the current economic recession could impact retail and industrial gas usage by Union Gas distribution customers in the near term. Distribution s earnings are affected significantly by weather during the winter heating season.

In December 2009, the OEB issued its policy report on the Cost of Capital for Ontario s Regulated Utilities. In that report, the OEB determined that Utility Return on Equity should be increased by approximately 125 basis points. Union Gas is currently assessing how and when that increase might be implemented in light of its multi-year incentive regulation parameters.

From 2002 through 2009, the Canadian dollar has generally strengthened compared to the U.S. dollar, which favorably affected earnings during these periods, except in the fourth quarter 2008 and the first quarter 2009 when the Canadian dollar weakened significantly in a very short period of time. Changes in the exchange rate or any other factors are difficult to predict and may affect future results.

Western Canada Transmission & Processing

	2009	2008	Increase (Decrease)	2007	Increase (Decrease)
	(in millions, except where noted)				
Operating revenues	$ 1,115	$ 1,482	$ (367)	$ 1,266	$ 216
Operating expenses					
Natural gas and petroleum products purchased	222	496	(274)	361	135
Operating, maintenance and other	407	445	(38)	405	40
Depreciation and amortization	144	147	(3)	135	12
Operating income	342	394	(52)	365	29
Other income and expenses	1	5	(4)		5
Noncontrolling interests		1	(1)	6	(5)
EBIT	$ 343	$ 398	$ (55)	$ 359	$ 39
Pipeline throughput, TBtu	604	615	(11)	596	19
Volumes processed, TBtu	655	698	(43)	709	(11)
Empress inlet volumes, TBtu	737	820	(83)	722	98

2009 Compared to 2008

Operating Revenues. The $367 million decrease was driven primarily by:

- a $263 million decrease due to lower NGL product prices associated with the Empress operations,
- a $101 million decrease due primarily to lower NGL sales volumes related to the Empress operations as a result of reduced natural gas production by producers caused by lower natural gas prices and high royalties, and
- a $71 million decrease as a result of a weaker Canadian dollar, partially offset by
- a $53 million increase resulting primarily from higher gathering and processing revenues due to higher firm contract revenue, and
- a $15 million increase in revenues to recover carbon tax expense from customers.

Natural Gas and Petroleum Products Purchased. The $274 million decrease was driven primarily by:

- a $186 million decrease arising from primarily lower prices of natural gas purchased for the Empress facility, a $75 million decrease mainly as a result of lower volumes of natural gas purchased for the Empress facility, and

a $13 million decrease caused by a weaker Canadian dollar.

Operating, Maintenance and Other. The $38 million decrease was driven primarily by:

- a $32 million decrease caused by a weaker Canadian dollar, and
- a $29 million decrease in plant fuel and electricity costs at the Empress facility, partially offset by
- a $15 million increase in the carbon tax expense, and
- an $8 million increase in maintenance and other project costs.

Depreciation and Amortization. The $3 million decrease was driven primarily by:

- an $8 million decrease resulting from a weaker Canadian dollar, mostly offset by
- a $5 million increase as a result of expansion projects placed into service in 2009.

EBIT. The $55 million decrease was driven primarily by lower NGL gross margins that negatively impacted the Empress operations, as well as a weaker Canadian dollar, partially offset by higher gathering and processing revenues, and lower plant fuel and electricity costs at the Empress facility.

2008 Compared to 2007

Operating Revenues. The $216 million increase was driven primarily by:

- a $155 million increase primarily due to stronger NGL sales prices and higher volumes associated with the Empress operations. The higher volumes were a result of successful marketing efforts for NGL extraction rights in 2008, as well as a plant maintenance turnaround which reduced inlet volumes for a period during 2007.
- a $25 million increase mainly due to higher sales prices and processing volumes in the Pine River area of northeastern BC. The higher volumes were as a result of new contracts in 2008 and a plant maintenance turnaround that caused the plant to be unavailable for processing during this period in 2007.
- an $18 million increase resulting from a stronger Canadian dollar, and
- an $8 million increase in carbon tax revenue as levied by the BC government effective July 1, 2008 that is recoverable from customers.

Natural Gas and Petroleum Products Purchased. The $135 million increase was driven primarily by higher prices and volumes of natural gas and NGLs purchased for the Empress facility.

Operating, Maintenance and Other. The $40 million increase was driven primarily by:

- an $18 million increase due to higher labor and benefit costs, as well as higher maintenance costs related to year over year price escalations,

- a $12 million increase in plant fuel and electricity costs at the Empress facility, and

- an $8 million increase in carbon tax expense.

Depreciation and Amortization. The $12 million increase was driven primarily by increased pipeline depreciation rates as a result of a rate settlement with customers.

Other Income and Expenses. The $5 million increase was driven primarily by higher equity earnings from the McMahon cogeneration facility due to increased gas sales and electricity revenue in 2008, as well as the negative mark-to-market impact of the McMahon gas contract hedge during the fourth quarter of 2007 prior to this position being designated as a cash flow hedge.

Noncontrolling Interests. The $5 million decrease was driven primarily by the purchase of the Income Fund in the second quarter of 2008. Prior to the acquisition, the Income Fund indirectly held 54% of Spectra Energy s consolidated Canadian Midstream operations and Westcoast Energy Inc. (Westcoast) indirectly held the remaining 46%.

EBIT. The $39 million increase was driven primarily by higher NGL prices and volumes that benefited the Empress operations, higher processing revenues and a stronger Canadian dollar. These increases were partially offset by higher operating expenses, including higher plant fuel and electricity costs.

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 a plant is out of service and increase operating costs as a result of the turnaround maintenance work. Western Canada Transmission & Processing s 17 processing plants are generally scheduled for turnaround work every three to four years, with the work being staggered to prevent significant outages at any given time in a single geographic area. Future earnings will also 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.

From 2002 through 2009, the Canadian dollar has generally strengthened compared to the U.S. dollar, which favorably affected earnings during these periods, except in the fourth quarter 2008 and the first quarter of 2009 when the Canadian dollar weakened significantly in a very short period of time. Changes in the exchange rate or any other factors are difficult to predict and may affect future results.

While exploration and drilling activities slowed somewhat in certain of our Western Canadian business areas in 2006 and 2007, overall long-term growth rates associated with our Western Canada operations increased during 2008 and were sustained in 2009 as a result of strong indicators of interest for continued natural gas exploration and drilling in the areas of British Columbia and Alberta that are in close proximity to our facilities. While current drilling levels are below recent historical averages, the continued strength of land sales and other indicators of development interest specifically relating to shale gas exploration and development support the increase in long-term growth rates that occurred in 2008 and were sustained in 2009.

Field Services

	2009	2008	Increase (Decrease)	2007	Increase (Decrease)
		(in millions, except where noted)			
Equity in earnings of unconsolidated affiliates	$ 296	$ 716	$ (420)	$ 533	$ 183
EBIT	$ 296	$ 716	$ (420)	$ 533	$ 183
Natural gas gathered and processed/transported, TBtu/d(a,b)	6.9	7.1	(0.2)	6.8	0.3
NGL production, MBbl/d(a,c)	358	360	(2)	363	(3)
Average natural gas price per MMBtu(d)	$ 3.99	$ 9.03	$ (5.04)	$ 6.86	$ 2.17
Average NGL price per gallon(e)	$ 0.71	$ 1.23	$ (0.52)	$ 1.11	$ 0.12

(a) Reflects 100% of volumes.
(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.

2009 Compared to 2008

EBIT. Lower equity in earnings of $420 million were primarily the result of the following variances, each representing our 50% ownership portion of the earnings drivers at DCP Midstream:

- a $492 million decrease from commodity-sensitive processing arrangements, due to decreased commodity prices,
- a $48 million decrease in gathering and processing margins primarily attributable to lower volumes resulting primarily from reduced drilling and lower recoveries and efficiencies, partially offset by the impact of hurricanes in 2008,
- a $28 million decrease due to higher net interest expense resulting from increased debt associated with growth, acquisitions and a special distribution paid in 2008, and higher borrowing costs during 2009,
- a $23 million decrease in earnings from DCP Partners primarily as a result of mark-to-market losses on derivative instruments used to protect distributable cash flows, compared to gains in 2008, and
- a $9 million decrease primarily attributable to gains on sales of assets in 2008, partially offset by
- a $135 million gain associated with partnership units previously issued by DCP Partners,
- a $29 million increase in NGL trading and gas marketing, and
- a $17 million increase primarily as a result of lower operating and maintenance expenses due to a cost reduction initiative and the impact of decreased commodity prices in 2009, partially offset by higher depreciation expense as a result of capital spending and acquisitions in 2008 and 2009.

2008 Compared to 2007

EBIT. Higher equity in earnings of $183 million was primarily the result of the following variances, each representing our 50% ownership portion of the earnings drivers at DCP Midstream:

- a $175 million increase from commodity-sensitive processing arrangements, due to increased commodity prices,
- a $22 million increase in earnings from DCP Partners, primarily as a result of mark-to-market gains on hedges used to protect distributable cash flows,
- a $20 million increase in gathering and processing margins primarily attributable to increased natural gas and NGL volumes and improved efficiencies in non-weather impacted areas and contract yields, partially offset by hurricane and adverse weather events,
- a $9 million increase in marketing margins related to timing, and

a $6 million increase in other income, which is primarily due to gains on the sale of assets in the fourth quarter 2008, partially offset by

a $36 million decrease resulting from higher depreciation expense and increased operating and maintenance expenses due to growth and asset acquisitions, partially offset by decreased general and administrative costs as a result of $12 million of costs in 2007 associated with DCP Midstream s initiative to create stand alone corporate functions separate from its two partners, and

a $22 million decrease due to higher net interest expense resulting from the increased debt associated with acquisitions in 2007 and 2008.

Supplemental Data

Below is supplemental information for DCP Midstream s operating results (presented at 100%):

	2009	2008	2007
		(in millions)	
Operating revenues	$ 8,560	$ 16,398	$ 13,154
Operating expenses	8,026	14,704	11,959
Operating income	534	1,694	1,195
Other income and expenses	24	20	29
Interest expense, net	254	198	154
Income tax expense (benefit)	(2)	(3)	11
Net income	306	1,519	1,059
Net income (loss) noncontrolling interests	(16)	88	(15)
Net income attributable to members interests	$ 322	$ 1,431	$ 1,074

As a result of the adoption of a new accounting standard in 2009, DCP Midstream reclassified to equity certain deferred gains on sales of common units in DCP Partners. Our proportionate 50% share, totaling $135 million, was recorded in Equity in Earnings of Unconsolidated Affiliates in the Consolidated Statement of Operations in 2009.

Matters Affecting Future Field Services Results

In the near term, softening of natural gas prices, reduced demand for natural gas, potential reduction in producers available capital and cash flows, and the recent downturn in the economy are causing a reduction in levels of drilling activity and associated natural gas throughput volumes. The impact of these factors will vary across Field Services broad geographic locations. Generally, drilling levels increased during the second half of 2009; however, they decreased compared to their peak in 2008. Since the peak in 2008, DCP Midstream has experienced lower gas throughput volumes at certain of our natural gas assets due to reduced drilling levels. Throughput volumes could decline further should natural gas prices and drilling levels decline further.

Other

	2009	2008	Increase (Decrease)	2007	Increase (Decrease)
			(in millions, except where noted)		
Operating revenues	$ 47	$ 45	$ 2	$ 31	$ 14
Operating expenses	130	125	5	150	(25)
Operating loss	(83)	(80)	(3)	(119)	39
Other income and expenses	9	2	7	7	(5)
EBIT	$ (74)	$ (78)	$ 4	$ (112)	$ 34

2009 Compared to 2008

EBIT. The $4 million increase in EBIT reflects slightly lower corporate costs in 2009.

2008 Compared to 2007

EBIT. The $34 million increase was primarily due to $23 million of costs associated with the spin-off of Spectra Energy in 2007 and the favorable resolution of an insurance indemnity for $8 million in 2008.

Matters Affecting Future Other Results

Future Other results will continue to include corporate and business services we provide for our operations, and will also include operating costs and self-insured losses associated with our captive insurance entities. The results for Other could be impacted by the number and severity of insured property losses, particularly during hurricane season.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The application of accounting policies and estimates is an important process that continues to evolve as our operations change and accounting guidance is issued. We have identified a number of critical accounting policies and estimates that require the use of significant estimates and judgments.

We base our estimates and judgments on historical experience and on other various assumptions that we 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. We discuss our critical accounting policies and estimates and other significant accounting policies with our Audit Committee.

Regulatory Accounting

We account for certain of our regulated operations under accounting for regulated entities. As a result, we record assets and liabilities that result from the regulated ratemaking process that would not be recorded under generally accepted accounting principles 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. We continually assess 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, we believe our 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, 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 $964 million as of December 31, 2009 and $862 million as of December 31, 2008. Total regulatory liabilities were $678 million as of December 31, 2009 and $452 million as of December 31, 2008.

In 2009, we recorded $18 million of charges due to the discontinuance of rate regulated accounting treatment by SESH as a result of significant increases in construction costs of the SESH pipeline beyond the original estimates. These costs were not accompanied by equivalent increases in negotiated rates charged by SESH to its customers.

In 2008, we recorded a $44 million charge representing our share of impaired assets associated with the Islander East pipeline project. Triggered by certain 2008 legal and economic events, costs associated with this project were evaluated as to probability of recovery under FERC-approved tariff rates associated with any future alternative project plan. See Note 10 of the Notes to Consolidated Financial Statements for further discussion.

Impairment of Goodwill

We perform our goodwill impairment test annually and evaluate goodwill when events or changes in circumstances indicate that its carrying value may not be recoverable. Prior to 2009, we performed the annual impairment testing of goodwill using August 31 as the measurement date. Our financial and strategic planning process, including the preparation of long-term cash flow projections, commences in October and typically concludes in January of the following year. These long-term cash flow projections are a key component in performing our annual impairment test of goodwill. This planning cycle historically created significant constraints in the availability of both information and human resources needed to provide the appropriate projections to be used in the goodwill impairment test using the August 31 test date. Accordingly, effective with our 2009 annual impairment test, we changed our goodwill impairment test date from August 31 to April 1. We believe that using the April 1 date will alleviate the information and resource constraints that historically existed during the third quarter and will better coincide with the completion of our long-term financial projections. We believe that this accounting change is to an alternative accounting principle that is preferable under the circumstances and did not result in the delay, acceleration or avoidance of an impairment charge. We have determined that this change in accounting principle does not result in adjustments to our 2008 or 2007 Consolidated Financial Statements when applied retrospectively as our base assumptions used in the August 31 measurement date would not have changed significantly had we used April 1 as the measurement date.

We had goodwill balances of $3,948 million at December 31, 2009 and $3,381 million at December 31, 2008. The increase in goodwill in 2009 was primarily the result of foreign currency translation and $150 million of goodwill at U.S Transmission associated with the acquisition of NOARK in May 2009. There was no impairment of goodwill recorded during 2009, 2008 or 2007. The majority of our goodwill relates to the acquisition of Westcoast in March 2002, which owns the majority of our Canadian operations. As of the acquisition date or upon a change in reporting units, we allocate goodwill to a reporting unit, which we define as an operating segment or one level below an operating segment. We perform an annual goodwill impairment test and update 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 determination of fair value include the use of an appropriate discount rate and estimated future cash flows. In estimating cash flows, we incorporate expected long-term growth rates in key markets served by our operations, regulatory stability, the ability to renew contracts, commodity prices (where appropriate) and foreign currency exchange rates, as well as other factors that affect our revenue, expense and capital expenditure projections.

The long-term growth rates used for our reporting units reflect continued expansion of our assets, driven by new natural gas supplies such as shale gas in North America and, notwithstanding the current economic downturn, increasing demand for capacity on our pipeline systems. For our 2009 goodwill impairment analysis, we assumed a weighted-average long-term growth rate of 4%. If we had assumed a zero growth rate for any reporting unit, there would have been no impairment of goodwill in 2009.

We continue to monitor the effects of the economic downturn that global economies are currently facing on the long-term cost of capital utilized to calculate our reporting unit fair values. For our 2009 goodwill impairment analysis, we assumed a weighted-average cost of capital ranging from 6.4% to 8.5% for our reporting units. If we had assumed a 100 basis point increase in cost of capital for any of our reporting units, there would have been no impairment of goodwill in 2009. Additionally, for our regulated businesses in Canada, if an increase in the cost of capital occurred, the effect on the corresponding reporting unit s fair value would be ultimately offset by a similar increase in the reporting unit s regulated revenues since those rates include a component that is based on the reporting unit s cost of capital.

Based on the results of our annual impairment testing, the fair values of our reporting units at April 1, 2009 significantly exceeded their carrying values. No triggering events or changes in circumstances occurred during the period April 1, 2009 (our testing date) through December 31, 2009 that would warrant re-testing for goodwill impairment.

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. We believe 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.

Capital market declines and volatility experienced during 2008 and 2009 have adversely impacted the market value of investment assets used to fund Spectra Energy s defined benefit employee retirement plans. Future changes in plan asset returns, assumed discount rates and various other factors related to the participants in our pension and post-retirement plans will impact future pension expense and funding.

The expected return on plan assets is important, since certain of our pension and other post-retirement benefit plans are funded. Expected long-term rates of return on plan assets are developed by using a weighted average of expected returns for each asset class to which the plan assets are allocated. For 2009, the assumed average return was 7.25% for the U.S. pension plan assets and 6.50% for other post-retirement benefit assets. A change in the rate of return of 25 basis points for the U.S. pension and other post-retirement benefit assets would impact annual benefit expense by approximately $1 million before tax. The assumed average return for the Canadian pension plan assets was 7.00%. A change in the rate of return of 25 basis points for the Canadian pension assets would impact annual benefit expense by approximately $2 million before tax. The Canadian other post-retirement benefit plans are not funded.

Since pension and other post-retirement benefit liabilities are measured on a discounted basis, the discount rate is also a significant assumption. Discount rates used for our defined benefit and other post-retirement benefit plans are based on the yields constructed from a portfolio of high-quality bonds for which the timing and amount of cash outflows approximate the estimated payouts of the plans. The average discount rates of 5.93% for the U.S. plans and 6.47% for the Canadian plans used to calculate 2009 plan expenses represent a weighted average of the applicable rates. A 25 basis point change in the discount rates would not impact annual benefit expense for the U.S. plans but would impact the Canadian plans by approximately $2 million before tax.

See Note 23 of Notes to Consolidated Financial Statements for more information on pension and other post-retirement benefits.

LIQUIDITY AND CAPITAL RESOURCES

Known Trends and Uncertainties

We will rely primarily upon cash flows from operations and various financing transactions to fund our liquidity and capital requirements for 2010, which may include issuances of short-term and long-term debt. As of December 31, 2009, we had negative working capital of approximately $1,066 million. This balance includes short-term borrowings and commercial paper totaling $162 million and current maturities of long-term debt of $809 million. We also have access to six revolving credit facilities, with total combined capacities of approximately $2.3 billion available at December 31, 2009. With the exception of the Spectra Energy Partners facility which is used for bank borrowings, these facilities will be used principally as back-stops for commercial paper programs or for the issuance of letters of credit. Our consolidated capital structure includes long-term debt, short-term borrowings, commercial paper and preferred stock of subsidiaries. As of December 31, 2009, our capital structure was 56% debt, 40% common equity of controlling interests and 4% noncontrolling interests and preferred stock of subsidiaries. See Credit Ratings Summary Other Financing Matters for discussions of effective shelf registrations and available credit facilities.

Cash flows from operations for our businesses are fairly stable given that 90% of revenues are derived from regulated operations that primarily represent fee-based services. However, total operating cash flows are subject to a number of factors, including, but not limited to, earnings sensitivities to weather, commodity prices, distributions from our equity affiliates and the timing of regulatory cost recovery approvals. See Part I, Item 1A. Risk Factors for further discussion.

In particular, cash distributions from our equity affiliate DCP Midstream can fluctuate, primarily as a result of earnings sensitivities to commodity prices, as well as their levels of capital expenditures and other investing activities. DCP Midstream funds its operations and investing activities primarily from its operating cash flows, third-party debt and equity transactions associated with DCP Partners. DCP Midstream is required to make quarterly tax distributions to us based on allocated taxable income. In addition to tax distributions, periodic distributions are determined by DCP Midstream s board of directors based on net income, operating cash flows and other factors, including capital expenditures and other investing activities, commodity prices outlook and the credit environment. We received total tax and periodic distributions from DCP Midstream of $101 million in 2009, $930 million in 2008 and $618 million in 2007. As discussed in Note 1 of the Notes to Consolidated Financial Statements, a portion of these distributions are classified within Operating Cash Flows and the remainder is classified as Investing Cash Flows. Reduced distributions in 2009 directly corresponded to the lower average commodity prices experienced during 2009 as compared to 2008 and 2007. We continually assess the effect of commodity prices and other activities at DCP Midstream on cash expected to be received from DCP Midstream, and adjust our expansion or other activities as necessary.

Capital market declines and volatility experienced during 2008 and 2009 have adversely impacted the market value of investment assets used to fund Spectra Energy s defined benefit employee retirement plans. See further discussion of the expected impact of these changes under Quantitative and Qualitative Disclosures About Market Risk Equity Price Risk. Future changes in plan asset returns, assumed discount rates and various other factors related to the participants in our pension and post-retirement plans will impact future pension expense and funding.

As we execute on our strategic objectives around organic growth and expansion projects, expansion expenditures are expected to average $1 billion per year over the next few years. The timing and extent of these expenditures are likely to vary significantly from year to year, depending primarily on general economic conditions and market requirements. Given that we expect to continue to pursue expansion opportunities over the next several years and also given the normal scheduled maturities of our existing debt instruments, capital resources will continue to include long-term borrowings. We remain committed to maintaining a capital structure and liquidity profile that continues to support an investment-grade credit rating. As part of this commitment and in response to the risks to our capital structure that would be posed by further weakening of the Canadian dollar, on February 13, 2009, we issued 32.2 million shares of our common stock and received net proceeds of $448 million. We continue to monitor market requirements and our available liquidity and will make adjustments to these long-term plans as needed.

Operating Cash Flows

Net cash provided by operating activities decreased $45 million to $1,760 million in 2009 compared to 2008. This change was driven primarily by:

- a decrease of $582 million in distributions received from unconsolidated affiliates in 2009, driven by lower commodity prices at DCP Midstream, partially offset by

- a $402 million net working capital change at Union Gas primarily resulting from higher amounts of approved gas cost collections from customers that exceeded the actual cost of gas in 2009 compared to such amounts collected in 2008. Gas cost collections that have been deferred will be refunded to customers in future periods, and

- a $222 million decrease in tax payments in 2009, primarily the result of the recent U.S. Economic Stimulus Plan, which deferred significant amounts of tax payments to future periods.

Net cash provided by operating activities increased $338 million to $1,805 million in 2008 compared to 2007. This change was driven primarily by:

- an increase of $208 million in distributions received from unconsolidated affiliates in 2008, primarily from DCP Midstream, and

- a January 2007 payment of $100 million, which was accrued at December 31, 2006, to resolve certain litigation matters associated with discontinued LNG operations.

Investing Cash Flows

Net cash flows used in investing activities decreased $888 million to $1,000 million in 2009 compared to 2008. This change was driven primarily by:

- a $989 million decrease in capital and investment expenditures in 2009 as a result of the planned reduction in capital expansion levels for 2009,

- a $186 million receipt from SESH in 2009 to repay our loan to them, and

- a $274 million acquisition of units of the Income Fund in 2008 that were held by non-affiliated holders, partially offset by

- the $295 million acquisition of NOARK in 2009.

The $186 million receipt from SESH, recorded as Receipt From Affiliate Repayment of Loan on the Consolidated Statement of Cash Flows, represents repayment of the remaining balance of an outstanding loan receivable from SESH. A portion of these funds were from the proceeds of a debt issuance by SESH.

In 2009, we also received a $148 million special distribution from Gulfstream from the proceeds of a debt issuance by Gulfstream, of which $144 million was classified as Cash Flows from Investing Activities Distributions Received From Unconsolidated Affiliates on the Consolidated Statement of Cash Flows.

Net cash flows used in investing activities increased $344 million to $1,888 million in 2008 compared to 2007. This change was driven primarily by:

- a $543 million increase in capital and investment expenditures and loans to unconsolidated affiliates in 2008 as a result of expansion projects underway, primarily at U.S. Transmission, and

- the $274 million acquisition of the units of the Income Fund in 2008, partially offset by a net increase of $269 million in proceeds from the sales and maturities of available-for-sale securities primarily at Spectra Energy Partners,

increased distributions received from unconsolidated affiliates that represented returns of capital, primarily from DCP Midstream, of $131 million in 2008, and

an increase of $90 million in net proceeds from the sales of other assets, primarily the sale of the Nevis and Brazeau plants in December 2008.

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.

	2009	2008 (in millions)	2007
Capital and Investment Expenditures(a)			
U.S. Transmission	$ 432	$ 1,400	$ 898
Distribution	224	373	369
Western Canada Transmission & Processing	353	222	195
Other	32	35	39
Total consolidated	$ 1,041	$ 2,030	$ 1,501

(a) Excludes the acquisitions of NOARK in 2009 and units of the Income Fund in 2008. See Note 3 of Notes to Consolidated Financial Statements for further discussion.

Capital and investment expenditures for 2009 totaled $1,041 million and included $517 million for expansion projects and $524 million for maintenance and other projects. We project 2010 capital and investment expenditures of approximately $1.6 billion, consisting of approximately $0.7 billion for U.S. Transmission, $0.3 billion for Distribution and $0.6 billion for Western Canada Transmission & Processing. Total projected 2010 capital and investment expenditures include approximately $1.0 billion of expansion capital expenditures and $0.6 billion for maintenance and upgrades of existing plants, pipelines and infrastructure to serve growth.

Expansion capital expenditures included several key projects placed into service in 2009 such as: Steckman Ridge, our 50%-owned, 12 Bcf natural gas storage facility in Pennsylvania; Northern Bridge, a 363 million-cubic-feet-per-day (MMcf/d) capacity expansion of the Texas Eastern system; South Peace Phase II, consisting of a 60-mile raw gas line in western Canada; and a 75 MMcf/d expansion of our existing West Doe gas treatment facility in western Canada.

Significant 2010 expansion project expenditures are expected to include:

TEMAX / Time III Expansion of the Texas Eastern pipeline system from both Oakford, Pennsylvania and Clarington, Ohio to an eastern Pennsylvania interconnection with a major interstate pipeline to transport an additional 455 MMcf/d of natural gas. In service phased in between 2010 and 2011.

TEAM 2012 150 MMcf/d expansion of the Texas Eastern pipeline system consisting of new pipeline construction. Project is designed to transport gas produced in the Marcellus Shale production regions to markets in the U.S. Northeast. In service is anticipated in late 2012.

Fort Nelson Expansion 830 MMcf/d expansion of the Fort Nelson system in western Canada, consisting of reactivation of existing processing capacity at the Fort Nelson gas plant, looping of area gathering pipelines, installation of new compression facilities and the construction of a new 250 MMcf/d processing facility. In service phased in between 2009 and 2012.

New Jersey-New York Expansion 800 MMcf/d expansion of the Texas Eastern pipeline system consisting of a new 16 mile pipeline extension into lower Manhattan and other related facilities. Project is designed to transport gas produced in the Marcellus Shale regions into New York. In service anticipated in late 2013.

Market Hub Storage Continuation of a multi-phase plan to increase the Egan and Moss Bluff facilities combined working capacity to 52 Bcf. These projects include two new storage caverns with a combined working capacity of 15 Bcf, additional header pipeline and meter capacity. These facilities are being constructed and phased into service through 2012.

East to West 281 MMcf/d expansion of the Algonquin system to facilitate west-bound transportation of gas delivered into the eastern end of the system from the Maritimes & Northeast Pipeline, the Northeast Gateway offshore facility and Suez LNG NA s Neptune Project. In service anticipated in late 2010.

Financing Cash Flows and Liquidity

Net cash used in financing activities totaled $803 million in 2009 compared to $214 million provided by financing in 2008. This $1,017 million change was driven primarily by:

an $774 million decrease in short-term borrowings in 2009 compared to a $249 million increase in the 2008 period,

a $113 million decrease in contributions from noncontrolling interests in 2009,

a $104 million increase in distributions to noncontrolling interests in 2009, primarily from proceeds of the debt issuance at M&N LLC, and

$104 million of net proceeds from the issuance of long-term debt in 2009 compared to $1,157 million in 2008, partially offset by

proceeds of $448 million in 2009 from the issuance of Spectra Energy common stock,

proceeds of $208 million in 2009 from the issuance of Spectra Energy Partners common units, and

repurchases of Spectra Energy common stock in 2008 of $600 million.

Net cash provided by financing activities totaled $214 million in 2008 compared to $191 million used in financing in 2007. This $405 million change was driven primarily by:

$1,157 million of net issuances of long-term debt in 2008 compared to $198 million of net redemptions in 2007, partially offset by

repurchases of Spectra Energy common stock in 2008 of $600 million,

proceeds of $230 million in 2007 from the issuance of Spectra Energy Partners common units, and

a $366 million increase in short-term borrowings and commercial paper in 2007 compared to a $249 million increase in 2008.

Significant Financing Activities 2009

Debt Issuances. The following debt issuances were completed during 2009 as part of our overall financing plan to fund capital expenditures and for other corporate purposes:

	Amount (in millions)	Interest Rate	Due Date

Spectra Capital	$	300	5.65%	2020
M&N LP		167(a)	4.34%	2019
M&N LLC		500	7.50%	2014

(a) U.S. dollar equivalent at time of issuance.

Funding of NOARK Acquisition. On May 4, 2009, Spectra Energy Partners acquired all of the ownership interests of NOARK from Atlas for approximately $295 million in cash. The transaction was initially funded by Spectra Energy Partners with $218 million drawn on its bank credit facility, $70 million borrowed under a credit facility with Spectra Energy that was created for the sole purpose of funding a portion of the acquisition, and $7 million of cash on hand. This transaction was partially refinanced by Spectra Energy Partners in the second quarter of 2009 through the issuance of 9.8 million common units to the public, representing limited partner interests, and 0.2 million general partner units to Spectra Energy, resulting in net proceeds of $212 million and a reduction of our ownership interest in Spectra Energy Partners from 84% to 74%. Funds from the sale of the partner units were used by Spectra Energy Partners to repay the $70 million owed to Spectra Energy and $142 million of the amount initially drawn on the Spectra Energy Partners bank credit facility. Effective with the repayment to Spectra Energy, the credit facility with Spectra Energy was terminated.

Common Stock Issuance. On February 13, 2009, in order to further protect our capitalization structure against a potential extreme decline in the Canadian dollar, we issued 32.2 million shares of our common stock and received net proceeds of $448 million. We used the net proceeds to repay commercial paper as it matured. Borrowings from the commercial paper were used primarily for capital expenditures and for other general corporate purposes.

Significant Financing Activities 2008

Debt Issuances. The following debt issuances were completed during 2008:

	Amount (in millions)	Interest Rate	Due Date
Spectra Capital	$ 500	6.20%	2018
Spectra Capital	250	5.90%	2013
Spectra Capital	250	7.50%	2038
Union Gas	198(a)	5.35%	2018
Union Gas	281(a)	6.05%	2038
Westcoast	48(a)	5.60%	2019
Westcoast	250(a)	5.60%	2019

(a) U.S. dollar equivalent at time of issuance

On July 31, 2008, M&N LLC paid $288 million to retire its outstanding bonds and bank debt and an additional $54 million early-extinguishment premium for the bonds. The payment of the premium, a regulatory asset, is presented within Cash Flows from Financing Activities Other on the Consolidated Statements of Cash Flows.

Common Stock Repurchases. We repurchased a cumulative total of $600 million of our outstanding common stock in 2008.

Significant Financing Activities 2007

In July 2007, we completed the IPO of Spectra Energy 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 Energy Partners upon closing of the IPO. Approximately $26 million of these proceeds was distributed to us, $194 million was used by Spectra Energy Partners to purchase qualifying investment grade securities, and $10 million was retained by Spectra Energy Partners to meet working capital requirements. Spectra Energy 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 us. In conjunction with the IPO, Spectra Energy Partners entered into a five-year $500 million facility that included both term and revolving borrowing capacity.

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.

Available Credit Facilities and Restrictive Debt Covenants

	Expiration Date	Credit Facilities Capacity	Outstanding at December 31, 2009			
			Commercial Paper	Revolving Credit	Letters of Credit	Total
			(in millions)			
Spectra Capital(a)						
Multi-year syndicated	2012	$ 1,500	$ 41	$	$ 27	$ 68
Westcoast(b)						
Multi-year syndicated	2011	190	84			84
364-day bilateral	2010	19			1	1
Union Gas(c)						
Multi-year syndicated	2012	475	37			37
364-day bilateral	2010	14			4	4
Spectra Energy Partners						
Multi-year syndicated	2012	500		240		240
Total		$ 2,698	$ 162	$ 240	$ 32	$ 434

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

(b) U.S. dollar equivalent at December 31, 2009. Two credit facilities, totaling 220 million Canadian dollars, each contain a covenant that requires the debt-to-total capitalization ratio to not exceed 75%.

(c) U.S. dollar equivalent at December 31, 2009. Two credit facilities, totaling 515 million Canadian dollars, each contain a covenant that requires the debt-to-total capitalization ratio to not exceed 75%. The multi-year syndicated facility 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.

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

Our credit agreements contain various financial and other covenants, including the maintenance of certain financial ratios. 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, 2009, we were in compliance with those covenants. In addition, our credit agreements allow for the 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. Our debt and credit agreements do not contain provisions that trigger an acceleration of indebtedness based solely on the occurrence of a material adverse change in our financial condition or results of operations.

As noted above, the terms of our Spectra Capital credit agreement require our consolidated debt-to-total-capitalization ratio to be 65% or lower. This ratio was 56% at December 31, 2009 compared to 62% as of December 31, 2008. The reduction in 2009 was primarily the result of the 2009 stock issuances by Spectra Energy and Spectra Energy Partners and the strengthened Canadian dollar. Our equity, and as a result, this ratio, is sensitive to significant movements of the Canadian dollar relative to the U.S. dollar due to the significance of our Canadian operations as discussed in Quantitative and Qualitative Disclosures About Market Risk Foreign Currency Risk. Based on the strength of our total capitalization as of December 31, 2009, however, it is not likely that a material adverse effect would occur as a result of a weakened Canadian dollar.

Credit Ratings Summary

	Standard and Poor s	Moody s Investor Service	Fitch Ratings	DBRS
As of February 12, 2010				
Spectra Capital(a)	BBB	Baa2	BBB	n/a
Texas Eastern(a)	BBB+	Baa1	BBB+	n/a
Westcoast(a)	BBB+	n/a	n/a	A(low)
Union Gas(a)	BBB+	n/a	n/a	A
M&N LLC(a)	BBB	Baa3	n/a	n/a
M&N LP(b)	A	A2/A3	n/a	A

(a) Represents senior unsecured credit rating.
(b) Represents senior secured credit rating. The A2 rating applies to M&N LP s 6.9% notes due 2019 and the A3 rating applies to its 4.34% notes due 2019.
n/a Indicates not applicable.

The above credit ratings depend upon, among other factors, the ability to generate sufficient cash to fund capital and investment expenditures, while maintaining the strength of the current balance sheet. These credit ratings could be negatively affected if, as a result of market conditions or other factors, these subsidiaries are unable to maintain their current balance sheet strength or if earnings or cash flow outlooks deteriorate materially.

Dividends. We currently anticipate an average dividend payout ratio over time of approximately 60-65% of estimated annual net income from controlling interests per share of common stock. The actual payout ratio, however, may vary from year to year depending on earnings levels. We expect to continue our policy of paying regular cash dividends. The declaration and payment of dividends are subject to the sole discretion of our Board of Directors and will depend upon many factors, including the financial condition, earnings and capital requirements of our operating subsidiaries, covenants associated with certain debt obligations, legal requirements, regulatory constraints and other factors deemed relevant by our Board of Directors. A dividend of $0.25 per common share was declared on January 5, 2010 and will be paid on March 15, 2010.

Other Financing Matters. Spectra Energy Corp and Spectra Capital have an automatic shelf registration statement on file with the SEC to register the issuance of unspecified amounts of various equity and debt securities, respectively. This registration statement expires in April 2010, and we intend to replace it with a similar registration statement. Spectra Energy Partners has an effective shelf registration statement on file with the SEC to register the issuance of limited partner common units and various debt securities up to $1.3 billion in the aggregate. In addition, as of the date of this filing, certain of our subsidiaries have 800 million Canadian dollars (approximately $760 million) available under shelf registrations for issuances in the Canadian market, of which 400 million expires in August 2010 and 400 million expires in September 2010.

Off-Balance Sheet Arrangements

We 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 Note 18 of Notes to Consolidated Financial Statements for further discussion of guarantee arrangements.

Most of the guarantee arrangements that we enter into enhance the credit standings 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 us having to honor our contingencies is largely dependent upon the future operations of our 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 our operations. As such, if we discontinued issuing these guarantee arrangements, there would not be a material impact to our consolidated results of operations, financial position or cash flows.

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

We do 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 Notes 17 and 18 of Notes to Consolidated Financial Statements.

Contractual Obligations

We enter into contracts that require payment of cash at certain specified periods, based on certain specified minimum quantities and prices. The following table summarizes our 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 2010.

Contractual Obligations as of December 31, 2009

	Payments Due By Period				
	Total	**2010**	**2011 & 2012**	**2013 & 2014**	**2015 & Beyond**
			(in millions)		
Long-term debt(a)	$ 15,860	$ 1,427	$ 2,192	$ 3,015	$ 9,226
Operating leases(b)	182	31	58	47	46
Purchase Obligations:(c)					
Firm capacity payments(d)	996	231	207	200	358
Energy commodity contracts(e)	708	630	46	32	
Other purchase obligations(f)	326	179	120	12	15
Other long-term liabilities on the Consolidated Balance Sheet(g)	51	51			
Total contractual cash obligations	$ 18,123	$ 2,549	$ 2,623	$ 3,306	$ 9,645

(a) See Note 14 of Notes to Consolidated Financial Statements. Amounts include estimated scheduled interest payments over the life of the associated debt.
(b) See Note 17.
(c) Purchase obligations reflected in the Consolidated Balance Sheets have been excluded from the above table.
(d) Includes firm capacity payments that provide us with uninterrupted firm access to natural gas transportation and storage.
(e) Includes contractual obligations to purchase physical quantities of NGLs and natural gas. Amounts include certain hedges as defined by applicable accounting standards. For contracts where the price paid is based on an index, the amount is based on forward market prices at December 31, 2009.
(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 cannot be determined.
(g) Includes estimated 2010 retirement plan contributions and estimated 2010 payments related to uncertain tax positions, including interest (see Notes 6 and 23). We are unable to reasonably estimate the timing of uncertain tax positions and interest payments in years beyond 2010 due to uncertainties in the timing of cash

settlements with taxing authorities and cannot estimate retirement plan contributions beyond 2010 due primarily to uncertainties about market performance of plan assets. Excludes cash obligations for asset retirement activities (see Note 13) because the amount of cash flows to be paid to settle the asset retirement obligations is not known with certainty as we may use internal or external resources to perform retirement activities. Amounts also exclude reserves for litigation and environmental remediation (see Note 17) and regulatory liabilities (see Note 5) because we are 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 primarily by taxable income for each discrete fiscal year.

Quantitative and Qualitative Disclosures About Market Risk

We are exposed to market risks associated with commodity prices, credit exposure, interest rates, equity prices and foreign currency exchange rates. We have established comprehensive risk management policies to monitor and manage these market risks. Our Chief Financial Officer is responsible for the overall governance of managing credit risk and commodity price risk, including monitoring exposure limits.

Commodity Price Risk

We are exposed to the impact of market fluctuations in the prices of NGLs and natural gas purchased as a result of our investment in DCP Midstream, and ownership of the Empress assets in western Canada and processing plants associated with our U.S. pipeline assets. Price risk represents the potential risk of loss from adverse changes in the market price of these energy commodities. Our 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.

We employ established policies and procedures to manage Spectra Energy s risks associated with Empress commodity price fluctuations, which may include the use of forward physical transactions as well as commodity derivatives. There were no significant commodity hedge transactions by Spectra Energy during 2009, 2008 or 2007.

Our equity affiliate, DCP Midstream, also has risk exposures primarily associated with market prices of NGLs and natural gas. DCP Midstream manages these risks separate from Spectra Energy, and utilizes various risk management strategies, including the use of commodity derivatives.

We are primarily exposed to market price fluctuations of NGL prices in our Field Services segment and to frac-spreads in the Empress operations in Canada. Since NGL prices have historically been correlated with crude oil prices, we disclose our NGL price sensitivities in terms of crude oil price changes. Based on a sensitivity analysis as of December 31, 2009 and 2008, at our forecasted NGL-to-oil price relationships, a $10 per barrel move in oil prices would affect our annual pre-tax earnings by approximately $100 million in 2010 ($90 million from Field Services and $10 million from U.S. Transmission) as compared with approximately $120 million in 2009 ($110 million from Field Services and $10 million from U.S. Transmission). Assuming crude oil prices average approximately $80 per barrel, each 1% change in the price relationship between NGLs and crude oil would change our annual pre-tax earnings by approximately $10 million. At crude oil prices above $80 per barrel, the impact of a 1% change in the NGL-to-oil price relationship would increase, and at crude oil prices below $80 per barrel, the impact of a 1% change in the NGL-to-oil price relationship would decrease.

With respect to the frac-spread risk related to Empress processing and NGL marketing activities in western Canada, as of December 31, 2009 and 2008, 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 our pre-tax earnings by approximately $12 million on an annual basis in 2010 and approximately $16 million in 2009.

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 our earnings could be significantly different than these estimates.

See also Notes 1 and 19 of Notes to Consolidated Financial Statements.

Credit Risk

Credit risk represents the loss that we would incur if a counterparty fails to perform under its contractual obligations. Our principal customers for natural gas transportation, storage, and gathering and processing services are industrial end-users, marketers, exploration and production companies, LDCs and utilities located throughout the United States and Canada. We have 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 our overall credit risk in that risk factors can negatively affect the credit quality of the 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, we analyze the counterparties financial condition prior to entering into an agreement, establish credit limits and monitor the appropriateness of those limits on an ongoing basis. We also obtain parental guarantees, cash or letters of credit from customers to provide credit support, where appropriate, based on our financial analysis of the customer and the regulatory or contractual terms and conditions applicable to each transaction. Approximately 85% of our credit exposures for transportation, storage, and gathering and processing services are with customers who have an investment-grade rating or equivalent based on our evaluation. However, we cannot predict to what extent our business would be impacted by deteriorating conditions in the economy, including possible declines in our customers creditworthiness. As a result of future capital projects for which natural gas producers may be the primary customer, the percentage of our customers who are rated investment-grade may decline.

We manage cash and restricted cash positions to maximize value while assuring appropriate amounts of cash are available, as required. We invest our 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. We discontinued investing in both asset-backed commercial paper and auction-rate securities in late 2007.

We 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, 2009.

Based on our policies for managing credit risk, our current exposures and our credit and other reserves, we do not anticipate a materially adverse effect on our consolidated financial position or results of operations as a result of non-performance by any counterparty.

Interest Rate Risk

We are exposed to risk resulting from changes in interest rates as a result of our issuance of variable and fixed-rate debt and commercial paper. We manage our interest rate exposure by limiting our variable-rate exposures to percentages of total debt and by monitoring the effects of market changes in interest rates. We also enter 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. See also Notes 1, 14 and 19 of Notes to Consolidated Financial Statements.

As of December 31, 2009, we had interest rate hedges in place for various purposes. We are party to pay floating receive fixed interest rate swaps with a total notional amount of $750 million to hedge against declines in the fair value of our fixed-rate debt that arise as a result of changes in market interest rates. These swaps also allow us to transform a portion of the underlying cash flows related to our long-term fixed-rate debt into variable-rate debt in order to achieve our desired mix of fixed and variable-rate debt. We are also a party to forward starting pay fixed receive floating interest rate swaps with a total notional amount of $150 million to effectively lock in a fixed underlying interest rate in anticipation of the refinancing of a scheduled maturity. At Spectra Energy Partners, we have third-party pay fixed receive floating interest rate swaps with a total notional amount of $40 million to mitigate our exposure to variable interest rates on loans outstanding under the Spectra Energy Partners revolving credit facility.

Based on a sensitivity analysis as of December 31, 2009, it was estimated that if market interest rates average 100 basis points higher (lower) in 2010 than in 2009, interest expense, net of offsetting impacts in interest income, would increase (decrease) by $10 million. Comparatively, based on a sensitivity analysis as of December 31, 2008, had interest rates averaged 100 basis points higher (lower) in 2009 than in 2008, it was estimated that interest expense, net of offsetting interest income, would have fluctuated by approximately $20 million. These amounts were estimated by considering the effect of the hypothetical interest rates on variable-rate debt outstanding, adjusted for interest rate hedges, investments, and cash and cash equivalents outstanding as of December 31, 2009 and 2008. The $10 million decrease in our estimated exposure to changes in market interest rates is primarily attributable to lower short-term borrowings and other variable-rate debt as of December 31, 2009 compared to December 31, 2008. If interest rates changed significantly, we would likely take action to manage our 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 our financial structure.

Equity Price Risk

Our cost 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 us to price fluctuations in equity markets. In addition, our 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. As previously discussed, equity markets have experienced significant declines in the past 18 months. These declines not only impact our cost of providing retirement and postretirement benefits, but also impact the funding level requirements of those benefits.

We manage equity price risk by, among other things, diversifying our investments in equity investments, setting target allocations of investment types, periodically reviewing actual asset allocations and rebalancing allocations if warranted, and utilizing outside consultants.

Foreign Currency Risk

We are exposed to foreign currency risk from investments and operations in Canada. 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. We may also use foreign currency derivatives, where possible, to manage risk related to foreign currency fluctuations. There were no significant foreign currency derivative transactions during 2009, 2008 or 2007.

To monitor our currency exchange rate risks, we use sensitivity analysis, which measures the effect of devaluation of the Canadian dollar. An average 10% devaluation in the Canadian dollar exchange rate during 2009 would have resulted in an estimated net loss on the translation of local currency earnings of approximately $35 million on our Consolidated Statement of Operations. In addition, if a 10% devaluation had occurred on December 31, 2009, the Consolidated Balance Sheet would be negatively impacted by $518 million through a cumulative translation adjustment in AOCI. At December 31, 2009, one U.S. dollar translated into 1.05 Canadian dollars.

As discussed earlier, we maintain credit facilities that typically include financial covenants which limit the amount of debt that can be outstanding as a percentage of total capital for Spectra Energy or of a specific subsidiary. Failure to maintain these covenants could preclude us from issuing commercial paper or letters of credit or borrowing under our revolving credit facilities 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 business. As a result of the impact of foreign currency fluctuations on our consolidated equity, these fluctuations have a direct impact on our ability to maintain certain of these financial covenants.

OTHER ISSUES

Global Climate Change. Policymakers at regional, federal and international levels continue to evaluate potential legislative and regulatory compliance mechanisms to achieve reductions in global GHG emissions in an effort to address the challenge of climate change. It is likely that our assets and operations in the U.S. and Canada are or will become subject to direct and indirect effects of current and possible future global climate change regulatory actions in the jurisdictions in which those assets and operations are located.

The current international climate framework, the United Nations-sponsored Kyoto Protocol, prescribes specific targets to reduce GHG emissions for developed countries for the 2008-2012 period. The Kyoto Protocol expires in 2012 and has not been signed by the United States. United Nations-sponsored international negotiations were held in Copenhagen, Denmark in December 2009 with the intent of defining a future agreement for 2012 and beyond. While the talks resulted in a non-binding political agreement, to date, a binding successor accord to the Kyoto Protocol has not been realized.

While Canada is a signatory to the Kyoto Protocol, the Canadian federal government has confirmed it will not achieve the targets within the timeframes specified. Instead, the government in 2008 outlined a regulatory framework mandating GHG reductions from large final emitters. Regulatory design details from the Government of Canada remain forthcoming. We expect a number of our assets and operations in Canada will be affected by pending federal climate change regulations. However, the materiality of any potential compliance costs is unknown at this time as the final form of the regulation and compliance options has yet to be determined by policymakers.

The province of British Columbia enacted a carbon tax, effective July 1, 2008. The tax applies to the purchase or use of fossil fuels, including natural gas. This tax is being recovered from customers through service tolls. British Columbia has also 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. In 2008, the province established additional interim GHG reduction targets of 6% below 2007 levels by 2012 and 18% below by 2016. The materiality of any potential compliance costs is unknown at this time as the final form of additional regulations and compliance options has yet to be determined by policymakers.

In July 2007, the province of Alberta adopted legislation which requires existing large emitters (facilities releasing 100,000 metric tons or more of GHG emissions annually) to reduce their annual emissions intensity by 12% beginning July 1, 2007. In 2009, one of our facilities was subject to this regulation. The regulation has not had a material impact on our consolidated results of operations, financial position or cash flows.

In the United States, climate change action is evolving at state, regional and federal levels. We expect that a number of our assets and operations in the United States could be affected by eventual mandatory GHG programs; however, the timing and specific policy objectives in many jurisdictions, including at the federal level, remain uncertain.

The United States is not a signatory to the Kyoto Protocol, nor has the federal government adopted a mandatory GHG emissions reduction requirement. However, the EPA issued the final Mandatory Greenhouse Gas Reporting rule in 2009 that will require annual reporting of GHG emissions data from certain of our U.S. operations beginning in 2010. This reporting requirement is not anticipated to have a material impact on our consolidated results of operations, financial position or cash flows. The EPA also proposed the Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule in 2009 to address how GHG emissions would be regulated under the existing Clean Air Act. This proposed rulemaking has not yet been finalized. In addition, several legislative proposals have been introduced and discussed in the U.S. Congress that would impose GHG emissions constraints, including H.R. 2454 the American Clean Energy and Security Act, which passed the House of Representatives in June 2009. To date, similar legislation has not been considered by the full U.S. Senate.

A number of states in the United States are establishing or considering state or regional programs that would mandate reductions in GHG emissions. These regional programs include the Regional Greenhouse Gas Initiative which applies only to power producers in select northeastern states, the Western Climate Initiative which includes a number of western states and the provinces of British Columbia, Ontario and Quebec, and the Midwestern Greenhouse Gas Reduction Accord which includes six midwestern states and one Canadian province. We expect a number of our assets and operations could be affected either directly or indirectly by state or regional programs. However, as the key details of future GHG restrictions and compliance mechanisms remain undefined, the likely future effects on our business 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, we cannot estimate the potential effect of proposed GHG policies on our future consolidated results of operations, financial position or cash flows. However, such legislation could materially increase our operating costs, require material capital expenditures or create additional permitting, which could delay proposed construction projects. We continue to monitor the development of greenhouse gas regulatory policies in both countries.

Other. For additional information on other issues, see Notes 5 and 17 of Notes to Consolidated Financial Statements.

New Accounting Pronouncements

See Note 1 of Notes to Consolidated Financial Statements for discussion.

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.

Item 8. Financial Statements and Supplementary Data.

Management s Annual Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining an adequate system of internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f) and 15d-15(f). Our internal control system was designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes, in accordance with generally accepted accounting principles. Because of inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with policies and procedures may deteriorate.

Our management, including our Chief Executive Officer and Chief Financial Officer, has conducted an evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2009 based on the framework in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on that evaluation, management concluded that our internal control over financial reporting was effective as of December 31, 2009.

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

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, 2009 and 2008, and the related consolidated statements of operations, equity and comprehensive income, and cash flows for each of the three years in the period ended December 31, 2009. 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, 2009, 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, 2009 and 2008, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2009, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009, 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, the 2008 and 2007 data contained in the consolidated financial statements and notes to consolidated financial statement have been retrospectively adjusted to reflect the reporting requirements of *ASC 810-10-65, Consolidations Overall Transition* (previously SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements*). The provisions of this standard were effective January 1, 2009.

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 *ASC 740-10, Income Taxes-Overall* (previously *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 25, 2010

SPECTRA ENERGY CORP

CONSOLIDATED STATEMENTS OF OPERATIONS

(In millions, except per-share amounts)

	Years Ended December 31, 2009	2008	2007
Operating Revenues			
Transportation, storage and processing of natural gas	$ 2,565	$ 2,343	$ 2,200
Distribution of natural gas	1,451	1,731	1,664
Sales of natural gas liquids	389	772	601
Other	147	228	239
Total operating revenues	4,552	5,074	4,704
Operating Expenses			
Natural gas and petroleum products purchased	1,098	1,586	1,416
Operating, maintenance and other	1,144	1,235	1,148
Depreciation and amortization	584	569	518
Property and other taxes	262	246	209
Total operating expenses	3,088	3,636	3,291
Gains on Sales of Other Assets and Other, net	11	42	13
Operating Income	1,475	1,480	1,426
Other Income and Expenses			
Equity in earnings of unconsolidated affiliates	369	778	596
Other income and expenses, net	37	66	53
Total other income and expenses	406	844	649
Interest Expense	610	636	633
Earnings From Continuing Operations Before Income Taxes	1,271	1,688	1,442
Income Tax Expense From Continuing Operations	353	496	440
Income From Continuing Operations	918	1,192	1,002
Income From Discontinued Operations, net of tax	5	2	25
Net Income	923	1,194	1,027
Net Income Noncontrolling Interests	75	65	70
Net Income Controlling Interests	$ 848	$ 1,129	$ 957
Common Stock Data			
Weighted-average shares outstanding			
Basic	642	622	632
Diluted	643	624	635
Earnings per share from continuing operations			
Basic	$ 1.31	$ 1.82	$ 1.48
Diluted	$ 1.31	$ 1.81	$ 1.48
Earnings per share			

Basic	$ 1.32	$ 1.82	$ 1.51
Diluted	$ 1.32	$ 1.81	$ 1.51
Dividends per share	$ 1.00	$ 0.96	$ 0.88

See Notes to Consolidated Financial Statements.

SPECTRA ENERGY CORP

CONSOLIDATED BALANCE SHEETS

(In millions)

	December 31, 2009	December 31, 2008
ASSETS		
Current Assets		
Cash and cash equivalents	$ 196	$ 214
Receivables (net of allowance for doubtful accounts of $14 and $12 at December 31, 2009 and 2008, respectively)	778	795
Inventory	321	279
Other	134	162
Total current assets	1,429	1,450
Investments and Other Assets		
Investments in and loans to unconsolidated affiliates	2,001	2,152
Goodwill	3,948	3,381
Other	407	417
Total investments and other assets	6,356	5,950
Property, Plant and Equipment		
Cost	19,960	17,569
Less accumulated depreciation and amortization	4,613	3,930
Net property, plant and equipment	15,347	13,639
Regulatory Assets and Deferred Debits	947	885
Total Assets	$ 24,079	$ 21,924

See Notes to Consolidated Financial Statements.

SPECTRA ENERGY CORP

CONSOLIDATED BALANCE SHEETS

(In millions, except per-share amounts)

	December 31, 2009	December 31, 2008
LIABILITIES AND EQUITY		
Current Liabilities		
Accounts payable	$ 333	$ 285
Short-term borrowings and commercial paper	162	936
Taxes accrued	139	105
Interest accrued	167	158
Current maturities of long-term debt	809	821
Other	885	739
Total current liabilities	2,495	3,044
Long-term Debt	8,947	8,290
Deferred Credits and Other Liabilities		
Deferred income taxes	3,113	2,789
Regulatory and other	1,634	1,566
Total deferred credits and other liabilities	4,747	4,355
Commitments and Contingencies		
Preferred Stock of Subsidiaries	225	225
Equity		
Preferred stock, $0.001 par, 22 million shares authorized, no shares outstanding		
Common stock, $0.001 par, 1 billion shares authorized, 647 million and 611 million shares outstanding at December 31, 2009 and 2008, respectively	1	1
Additional paid-in capital	4,700	4,104
Retained earnings	1,096	899
Accumulated other comprehensive income	1,328	536
Total controlling interests	7,125	5,540
Noncontrolling interests	540	470
Total equity	7,665	6,010
Total Liabilities and Equity	$ 24,079	$ 21,924

See Notes to Consolidated Financial Statements.

SPECTRA ENERGY CORP

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In millions)

	Years Ended December 31,		
	2009	2008	2007
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$ 923	$ 1,194	$ 1,027
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	598	581	534
Deferred income tax expense	177	161	110
Equity in earnings of unconsolidated affiliates	(369)	(778)	(596)
Distributions received from unconsolidated affiliates	195	777	569
Decrease (increase) in			
Receivables	143	(36)	59
Inventory	7	(76)	147
Other current assets	69	(36)	14
Increase (decrease) in			
Accounts payable	35	24	(93)
Taxes accrued	78	8	(61)
Other current liabilities	33	(52)	(198)
Other, assets	(62)	81	(1)
Other, liabilities	(67)	(43)	(44)
Net cash provided by operating activities	1,760	1,805	1,467
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures	(980)	(1,502)	(1,202)
Investments in and loans to unconsolidated affiliates	(61)	(528)	(285)
Acquisitions, net of cash acquired	(295)	(274)	(14)
Purchases of available-for-sale securities		(1,132)	(1,550)
Proceeds from sales and maturities of available-for-sale securities	32	1,256	1,405
Net proceeds from the sale of other assets		105	15
Distributions received from unconsolidated affiliates	164	218	87
Receipt from affiliate repayment of loan	186		
Other	(46)	(31)	
Net cash used in investing activities	(1,000)	(1,888)	(1,544)
CASH FLOWS FROM FINANCING ACTIVITIES			
Proceeds from the issuance of long-term debt	4,127	3,557	783
Payments for the redemption of long-term debt	(4,023)	(2,400)	(981)
Net increase (decrease) in short-term borrowings and commercial paper	(774)	249	366
Distributions to noncontrolling interests	(174)	(70)	(57)
Contributions from noncontrolling interests	2	115	9
Proceeds from the issuance of Spectra Energy common stock	448		
Proceeds from the issuance of Spectra Energy Partners, LP common units	208		230
Repurchases of Spectra Energy common stock		(600)	
Dividends paid on common stock	(631)	(598)	(558)
Other	14	(39)	17
Net cash provided by (used in) financing activities	(803)	214	(191)
Effect of exchange rate changes on cash	25	(11)	63

Net increase (decrease) in cash and cash equivalents	(18)	120	(205)
Cash and cash equivalents at beginning of period	214	94	299
Cash and cash equivalents at end of period	$ 196	$ 214	$ 94
Supplemental Disclosures			
Cash paid for interest, net of amount capitalized	$ 587	$ 611	$ 627
Cash paid for income taxes	100	322	393
Property, plant and equipment noncash accruals	24	44	109

See Notes to Consolidated Financial Statements.

SPECTRA ENERGY CORP

CONSOLIDATED STATEMENTS OF EQUITY AND COMPREHENSIVE INCOME

(In millions)

	Common Stock	Additional Paid-in Capital	Retained Earnings / Member s Equity	Accumulated Other Comprehensive Income Foreign Currency Translation Adjustments	Accumulated Other Comprehensive Income Other	Noncontrolling Interests	Total
December 31, 2006	$	$	$ 4,598	$ 1,156	$ (115)	$ 340	$ 5,979
Net income			957			70	1,027
Other comprehensive income							
Foreign currency translation adjustments				877		38	915
Reclassification of cash flow hedges into earnings					(2)		(2)
Pension and benefits impact					14		14
Total comprehensive income							1,954
Conversion to Spectra Energy Corp	1	4,597	(4,598)				
Recognition of uncertain income taxes			(26)				(26)
Transfer of net assets and liabilities from Duke Energy Corporation		12			(100)		(88)
Dividends on common stock			(558)				(558)
Spectra Energy Partners, LP common unit issuance						169	169
Distributions to noncontrolling interests						(57)	(57)
Contributions from noncontrolling interests						9	9
Effect of changing measurement date of pension benefit obligation			(5)				(5)
Stock-based compensation		49					49
Other, net						12	12
December 31, 2007	1	4,658	368	2,033	(203)	581	7,438
Net income			1,129			65	1,194
Other comprehensive income (loss)							
Foreign currency translation adjustments				(1,152)		(2)	(1,154)
Unrealized mark-to-market net loss on hedges					(11)		(11)
Reclassification of cash flow hedges into earnings					2		2
Pension and benefits impact					(133)		(133)
Total comprehensive income (loss)							(102)
Spectra Energy common stock repurchases		(600)					(600)
Dividends on common stock			(598)				(598)
Stock-based compensation		38					38
Purchase of Spectra Energy Income Fund units						(208)	(208)
Distributions to noncontrolling interests						(73)	(73)
Contributions from noncontrolling interests						115	115
Other, net		8				(8)	
December 31, 2008	1	4,104	899	881	(345)	470	6,010
Net income			848			75	923
Other comprehensive income							
Foreign currency translation adjustments				805		11	816
Unrealized mark-to-market net loss on hedges					(9)		(9)

Reclassification of cash flow hedges into earnings					1		1
Pension and benefits impact					(5)		(5)
Total comprehensive income							1,726
Dividends on common stock			(651)				(651)
Stock-based compensation		9					9
Spectra Energy common stock issuance		448					448
Spectra Energy Partners, LP common unit issuance		25				168	193
Reclassification of deferred gain on sale of units of Spectra Energy Partners, LP		59					59
Distributions to noncontrolling interests						(174)	(174)
Contributions from noncontrolling interests						2	2
Other, net		55				(12)	43
December 31, 2009	$ 1	$ 4,700	$ 1,096	$ 1,686	$ (358)	$ 540	$ 7,665

See Notes to Consolidated Financial Statements.

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SPECTRA ENERGY CORP

Notes to Consolidated Financial Statements

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1. Summary of Operations and Significant Accounting Policies

The terms we, our, us, and Spectra Energy as used in this report refer collectively to Spectra Energy Corp and its subsidiaries unless the context suggests otherwise. These terms are used for convenience only and are not intended as a precise description of any separate legal entity within Spectra Energy.

Nature of Operations. Spectra Energy Corp, through its subsidiaries and equity affiliates, owns and operates a large and diversified portfolio of complementary natural gas-related energy assets, operating in three key areas of the natural gas industry: gathering and processing, transmission and storage, and distribution. We provide 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. We also provide 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, we own 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 us and all of our outstanding common stock was distributed to Duke Energy s shareholders. Duke Energy s shareholders received one share of our 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.

In conjunction with the spin-off, on January 2, 2007, Duke Energy transferred to us the assets and liabilities, including related tax effects, associated with our 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 (AOCI) in the Consolidated Statement of 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 9 and 23 for further discussion of captive insurance and employee benefit plans.

Basis of Presentation. The accompanying Consolidated Financial Statements include our accounts, our majority-owned subsidiaries where we have control and those variable interest entities, if any, where we are the primary beneficiary.

Use of Estimates. To conform with generally accepted accounting principles (GAAP) in the United States, we make 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 our best available knowledge at the time, actual results could differ.

Fair Value Measurements. We measure the fair value of financial assets and liabilities by maximizing the use of observable inputs and minimizing the use of unobservable inputs. Fair value is the exchange price that would be received for an asset or paid to transfer a liability (an exit price) in the principal or most advantageous market for the asset or liability in an orderly transaction between market participants on the measurement date.

Cost-Based 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, we record assets and liabilities that result from the regulated ratemaking process that may not be recorded under GAAP for non-regulated entities. We continually assess 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, we believe our 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. We periodically evaluate our regulated assets, and consider factors such as regulatory changes and the effect of competition. If cost-based regulation ends or competition increases, we may have to reduce our 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.

Foreign Currency Translation. The Canadian Dollar has been determined to be the functional currency of our Canadian operations based on an assessment of the economic circumstances of those operations. Assets and liabilities of our Canadian operations 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 monthly exchange rates prevailing during the year. Gains and losses arising from transactions denominated in currencies other than the functional currency are included in the results of operations of the period in which they occur. Foreign currency transaction gains (losses) totaled $6 million in 2009, $11 million in 2008 and $(2) million in 2007, and are included in Other Income and Expenses, Net on the Consolidated Statements of Operations. Deferred taxes are not provided on translation gains and losses where we expect earnings of a foreign operation to be permanently reinvested.

Revenue Recognition. Revenues from the transportation, storage, distribution and sales of natural gas, and from the sales of natural gas liquids (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. There were no customers accounting for 10% or more of consolidated revenues during 2009, 2008 or 2007.

Stock-Based Compensation. 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. See Note 22 for further discussion.

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 expense 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 through Other Income and Expenses, Net for the equity component and Interest Expense for the interest expense component. After construction is completed, we are 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 2009 (an equity component of $21 million and an interest expense component of $19 million), $58 million in 2008 (an equity component of $33 million and an interest expense component of $25 million) and $40 million in 2007 (an equity component of $22 million and an interest expense component of $18 million).

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.

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.

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 were previously pledged as collateral against long-term debt as discussed in Note 14, are considered cash equivalents.

Inventory. Inventory consists primarily of natural gas and NGLs held in storage for transmission and processing, and also includes materials and supplies. Natural gas inventories primarily relate to the Distribution segment 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, as appropriate, 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,	
	2009	2008
	(in millions)	
Natural gas	$ 219	$ 180
NGLs	21	16
Materials and supplies	81	83
Total inventory	$ 321	$ 279

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 our Consolidated Statements of Cash Flows. Receivables and Other Current Liabilities each include $165 million as of December 31, 2009 and $134 million as of December 31, 2008 related to gas imbalances. Natural gas volumes owed to or by us are valued at natural gas market index prices as of the balance sheet dates.

Risk Management and Hedging Activities and Financial Instruments. Currently, our use of derivative instruments is primarily limited to interest rate positions. All derivative instruments that do not qualify for the normal purchases and normal sales exception are recorded on the Consolidated Balance Sheets at fair value. Cash inflows and outflows related to derivative instruments are a component of operating cash flows in the accompanying Consolidated Statements of Cash Flows.

Cash Flow and Fair Value Hedges. Qualifying energy commodity and other derivatives may be designated as either a hedge of a forecasted transaction (cash flow hedge) or a hedge of a recognized asset, liability or firm commitment (fair value hedge). For all hedge contracts, we prepare documentation of the hedge in accordance with accounting standards and assess whether the hedge contract is highly effective, both at inception and on a quarterly basis, in offsetting changes in cash flows or fair values of hedged items. We document hedging activity by instrument type (futures or swaps) and risk management strategy (commodity price risk or 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 Equity and Comprehensive Income as AOCI until earnings are affected by the hedged item. We discontinue hedge accounting prospectively when we have 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 transaction 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, we recognize the gain or loss on the derivative instrument, as well as the offsetting gain or loss 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 for the hedged item. 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.

Investments. We may actively invest a portion of our available cash and restricted cash balances in various financial instruments, including taxable or tax-exempt debt securities. In addition, we invest in short-term money market securities, some of which are restricted due to debt collateral and insurance requirements. We have classified all investments that are debt securities with maturity dates over one year as available-for-sale. These available-for-sale securities are carried at fair value. Investments in money market securities are also accounted for at fair value. 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. Restricted cash balances, primarily related to debt collateral and insurance requirements, totaled $134 million at December 31, 2009 and $69 million at December 31, 2008 and are classified within Investments and Other Assets Other on the Consolidated Balance Sheets. Changes in restricted cash balances are presented within Cash Flows from Investing Activities.

Goodwill. We perform our goodwill impairment test annually and evaluate goodwill when events or changes in circumstances indicate that its carrying value may not be recoverable. Prior to 2009, we performed the annual impairment testing of goodwill using August 31 as the measurement date. Our financial and strategic planning process, including the preparation of long-term cash flow projections, commences in October and typically concludes in January of the following year. These long-term cash flow projections are a key component in performing our annual impairment test of goodwill. This planning cycle historically created significant constraints in the availability of both information and human resources needed to provide the appropriate projections to be used in the goodwill impairment test using the August 31 test date. Accordingly, effective with our 2009 annual impairment test, we changed our goodwill impairment test date from August 31 to April 1. We believe that using the April 1 date will alleviate the information and resource constraints that historically existed during the third quarter and will better coincide with the completion of our long-term financial projections. We believe that this accounting change is to an alternative accounting principle that is preferable under the circumstances and did not result in the delay, acceleration or avoidance of an impairment charge. We have determined that this change in accounting principle does not result in adjustments to our 2008 or 2007 Consolidated Financial Statements when applied retrospectively as our base assumptions used in the August 31 measurement date would not have changed significantly had we used April 1 as the measurement date. We completed our goodwill impairment test as of April 1, 2009 and no impairments were identified. See Note 11 for further discussion.

We perform the annual review for goodwill impairment at the reporting unit level, which we have 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.

We primarily use 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, we incorporate expected long-term growth rates in key markets served by our operations, regulatory stability, the ability to renew contracts, commodity prices (where appropriate), and foreign currency exchange rates, as well as other factors that affect our revenue, expense and capital expenditure projections.

Property, Plant and Equipment. Property, plant and equipment are stated at historical cost less accumulated depreciation. We capitalize 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 that 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.

When we retire regulated property, plant and equipment, we charge the original cost plus the cost of retirement, less salvage value, to accumulated depreciation and amortization. When we sell entire regulated operating units, or retire 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.

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 expensed for U.S. rate-regulated enterprises. 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.

Long-Lived Asset Impairments. We evaluate 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 in 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, an 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.

We assess 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 natural gas available to our systems, the condition of an asset, a change in our intent to utilize the asset or a significant change in contracted revenues or regulatory recoveries would generally require us to reassess the cash flows related to the long-lived assets.

Asset Retirement Obligations. We recognize asset retirement obligations (AROs) for legal commitments associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or normal use of the asset and conditional AROs in which the timing or method of settlement are conditional on a future event that may or may not be within our control. The fair value of a liability for an ARO is recognized in the period in which it is incurred if a reasonable estimate of fair value can be made and is added to the carrying amount of the associated asset. This additional carrying amount is depreciated over the estimated useful life of the asset.

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. We expense 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.

Captive Insurance Reserves. We have captive insurance subsidiaries which provide insurance coverage to our consolidated subsidiaries as well as certain equity affiliates, on a limited basis, for various business risks and losses, such as workers compensation, property, business interruption and general liability. Liabilities include provisions for estimated losses incurred but not yet reported, 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.

Guarantees. Upon issuance or modification of a guarantee made by us, we recognize a liability at the time of issuance or material modification for the estimated fair value of the obligation we assume under that guarantee, if any. Fair value is estimated using a probability-weighted approach. We reduce the obligation over the term of the guarantee or related contract in a systematic and rational method as risk is reduced under the obligation.

Accounting For Sales of Stock by a Subsidiary. We adopted the provisions of Accounting Standards Codification (ASC) 810-10-65 Consolidations Overall Transition (previously Statement of Financial Accounting Standards (SFAS) No. 160, Noncontrolling Interests in Consolidated Financial Statements), effective January 1, 2009. Prior to the adoption of this accounting standard, we accounted for sales of stock by a subsidiary under Staff Accounting Bulletin (SAB) No. 51, Accounting for Sales of Stock of a Subsidiary. Under SAB No. 51, companies could 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. We had elected to treat such excesses as gains in earnings. Effective upon the adoption of the provisions of ASC 810-10-65, sales of stock by a subsidiary are required to be accounted for as equity transactions in those instances where a change in control does not take place, which effectively nullified the SAB No. 51 gain alternative. As a result of the adoption of the provisions of ASC 810-10-65, a $59 million deferred gain associated with the formation of Spectra Energy Partners, LP (Spectra Energy Partners), a majority-owned subsidiary, was reclassified from Regulatory and Other Deferred Credits and Other Liabilities to Additional Paid-in Capital in the Consolidated Balance Sheet on January 1, 2009. See Note 2 for further discussion.

Segment Reporting. 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 certain criteria are met. There is no aggregation within our defined business segments. A description of our reportable segments, consistent with how business results are reported internally to management and the disclosure of segment information is presented in Note 4.

Consolidated Statements of Cash Flows. We have made certain classification elections within our 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. We consider 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 classify 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 2009. The following new accounting pronouncements were adopted during 2009 and the effect of such adoption, if applicable, has been presented in the accompanying Consolidated Financial Statements:

ASC 105, Generally Accepted Accounting Principles (previously SFAS No. 168, The FASB Accounting Standards Codification™ and the Hierarchy of Generally Accepted Accounting Principles A Replacement of FASB Statement No. 162). This accounting standard results in the Financial Accounting Standards Board (FASB) Accounting Standards Codification (the Codification) becoming the source of authoritative U.S. GAAP recognized by the FASB to be applied by nongovernmental entities. Rules and interpretive releases of the SEC are also considered sources of authoritative GAAP for SEC registrants. The Codification supersedes all then-existing non-SEC accounting and reporting standards. All other nongrandfathered, non-SEC accounting literature not included in the Codification is nonauthoritative. The adoption of the provisions of this accounting standard did not change the application of existing GAAP for us, and as a result, did not have any impact on our consolidated results of operations, financial position or cash flows.

ASC 820, Fair Value Measurement and Disclosures (previously SFAS No. 157, Fair Value Measurements). This accounting standard defines fair value, establishes a framework for measuring fair value in GAAP and expands disclosures about fair value measurements. The FASB issued an amendment to this standard which delayed its effective date for nonfinancial assets and nonfinancial liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). The adoption of the provisions of this amended standard on January 1, 2009 for the measurement of our asset retirement obligations and for our goodwill impairment test did not have any impact on our consolidated results of operations, financial position or cash flows.

ASC 805, Business Combinations (previously SFAS 141R, Business Combinations). This accounting standard requires an 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. This standard 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. The adoption of the provisions of this standard on January 1, 2009 did not have an impact on our consolidated results of operations, financial position or cash flows.

ASC 810-10-65, Consolidations Overall Transition and Open Effective Date Information (previously SFAS No. 160, Noncontrolling Interests in Consolidated Financial Statements). This accounting standard requires all entities to report noncontrolling interests in subsidiaries as equity in the consolidated financial statements. This standard also requires that transactions between an entity and noncontrolling interests be treated as equity transactions. We adopted the provisions of this standard effective January 1, 2009 as required.

When adopting the presentation and disclosure items, retrospective application to conform previously reported financial statements is required. Accordingly, the 2008 and 2007 data contained in the Consolidated Financial Statements and Notes to Consolidated Financial Statements reflect the new reporting requirements of this standard. Changes to reflect the new measurement guidance for increases or decreases in ownership and other changes must be done prospectively. The new requirements for noncontrolling interests, results of operations and comprehensive income of subsidiaries change the presentation of operating results, related per-share information and equity. This standard requires net income and comprehensive income to be displayed for both the controlling and the noncontrolling interests. Additional required disclosures and reconciliations include a separate schedule that shows the effects of any transactions with the noncontrolling interests on the equity attributable to the controlling interest.

As discussed previously, a deferred gain associated with the formation of Spectra Energy Partners totaling $59 million was reclassified from Deferred Credits and Other Liabilities Regulatory and Other to Additional Paid-in Capital on the Consolidated Balance Sheet upon adoption of this standard on January 1, 2009. See Note 2 for further discussion.

In November 2008, the FASB ratified Emerging Issues Task Force (EITF) 08-06 (now ASC 323-10-35, Investments Equity Method and Joint Ventures Subsequent Measure), which addresses certain aspects of accounting for business combinations and noncontrolling interests on an entity s accounting for equity-method investments. The consensus indicates, among other things, that transaction costs for an investment should be included in the cost of the equity-method investment (and not expensed) and shares subsequently issued by the equity-method investee that reduce the investor s ownership percentage should be accounted for as if the investor had sold a proportionate share of its investment, with gains or losses recorded through earnings. For us, these amendments were effective for transactions occurring after December 31, 2008.

As discussed in Note 10, a $135 million increase to Equity in Earnings of Unconsolidated Affiliates was recorded in the first quarter of 2009 related to DCP Midstream s reclassification of certain deferred gains on sales of common units in its master limited partnership to equity as a result of their adoption of these amendments.

ASC 815-10, Derivatives and Hedging Overall (previously SFAS No. 161, Disclosures about Derivative Instruments and Hedging Activities an amendment of FASB Statement No. 133). This accounting standard expands the disclosure requirements related to derivative instruments and hedging activities with the intent to provide users of financial statements an enhanced understanding of how and why derivative instruments are used, how derivative instruments and related hedged items are accounted for and how they affect an entity s financial position, financial performance and cash flows. We adopted the provisions of this standard effective January 1, 2009 as required.

ASC 275-10, Risks and Uncertainties Overall and ASC 350-30, Intangibles Goodwill and Other General Intangible Other than Goodwill (previously FASB Staff Position (FSP) No. FAS 142-3, Determination of the Useful Life of Intangible Assets). These accounting standards amend the factors that should be considered in developing renewal or extension assumptions used to determine the useful life of a recognized intangible asset. The adoption of the provisions of these standards on January 1, 2009 had no impact on our consolidated results of operations, financial position or cash flows.

ASC 808-10, Collaborative Arrangements Overall (previously EITF 07-01, Accounting for Collaborative Arrangements). This accounting standard defines collaborative arrangements and establishes 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. An entity should report the effects of applying this accounting standard as a change in accounting principle through retrospective application to all prior periods presented for all arrangements existing as of the effective date. The adoption of the provisions of this standard on January 1, 2009 had no impact on our consolidated results of operations, financial position or cash flows.

ASC 260-10, Earnings per Share Overall (previously EITF 03-6-1, Determining Whether Instruments Granted in Share-Based Payment Transactions are Participating Securities). This standard addresses whether instruments granted in share-based payment transactions are participating securities prior to vesting and, therefore, need to be included in the earnings allocation in computing earnings per share (EPS) under the two-class method. The adoption of the provisions of this standard on January 1, 2009 had no material effect on our computation of EPS.

ASC 855-10, Subsequent Events Overall (previously SFAS No. 165, Subsequent Events). This accounting standard establishes general standards for the accounting for and disclosure of events that occur subsequent to the balance sheet date but before the financial statements of an entity are issued or are available to be issued. The adoption of the provisions of this standard effective June 30, 2009 did not have any impact on our consolidated results of operations, financial position or cash flows.

2008. There were no significant accounting pronouncements adopted during 2008 that had a material impact on our consolidated results of operations, financial position or cash flows.

2007. The following significant accounting pronouncement was adopted during 2007 and the effect of such adoption is presented in the accompanying Consolidated Financial Statements:

ASC 740-10, Income Taxes Overall (previously FASB Interpretation (FIN) No. 48 Accounting for Uncertainty in Income Taxes an Interpretation of FASB Statement No. 109). This accounting standard provides guidance on accounting for income tax positions where there is a level of uncertainty with respect to the recognition in financial statements. We implemented the provisions of this standard effective January 1, 2007, resulting in a cumulative effect decrease of $26 million to beginning 2007 Retained Earnings on the Consolidated Statement of Equity and Comprehensive Income.

Pending. The following new accounting pronouncement was issued but not adopted as of December 31, 2009:

ASC 810-10, Consolidations-Overall (previously SFAS No. 167, Amendments to FASB Interpretation No. 46(R)). In June 2009, the FASB issued this accounting standard which is intended to address (1) the effects on certain consolidation provisions as a result of the elimination of the concept of qualifying special-purpose entities and (2) constituent concerns about the application of certain consolidation provisions including those in which the accounting and disclosures do not always provide timely and useful information about an enterprise s involvement in a variable interest entity. For us, this accounting standard must be applied as of January 1, 2010. The adoption of the provisions of this standard did not have any impact on our consolidated results of operations, financial position or cash flows.

2. Spectra Energy Partners, LP

Formation. In 2007, Spectra Energy completed its initial public offering (IPO) of Spectra Energy Partners, a newly formed natural gas infrastructure master limited partnership. Spectra Energy contributed to Spectra Energy Partners 100% of the ownership of East Tennessee Natural Gas, LLC (East Tennessee), 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 (Gulfstream). Spectra Energy Partners issued 11.5 million common units to the public in the offering, representing 17% of Spectra Energy Partners outstanding equity. Spectra Energy retained an 83% equity interest in Spectra Energy Partners, including its common units, subordinated units and a 2% general partner interest. Net cash of approximately $230 million was received by Spectra Energy Partners upon closing of the IPO. Equity Noncontrolling Interests increased approximately $169 million in the Consolidated Balance Sheet as a result of the issuance of the common units.

Accounting rules in effect at the time of Spectra Energy Partners IPO allowed for recognition of a gain associated with such a sale only if the class of securities sold by the subsidiary did not contain any preference over the subsidiary s other classes of securities. Since the common units of Spectra Energy Partners have preferential cash distribution rights as compared to the subordinated units, we deferred recognition of the gain associated with the sale of the 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 $59 million and is included in Regulatory and Other Deferred Credits and Other Liabilities in the Consolidated Balance Sheet at December 31, 2008. As discussed in Note 1, the deferred gain was reclassified to Additional Paid-in Capital on January 1, 2009 upon the adoption of ASC 810-10-65.

Saltville. In 2008, Spectra Energy sold Saltville Gas Storage Company L.L.C. (Saltville) and the P-25 pipeline to Spectra Energy Partners for $107 million. Proceeds from the sale consisted of 4.2 million Spectra Energy Partners common units, 0.1 million general partner units and $5 million in cash. Spectra Energy s ownership of Spectra Energy Partners increased from 83% to 84% as a result of the issuance of the new common and general partner units. No gain or loss was recognized on the disposition since this transaction represented a transfer of entities under common control.

NOARK Pipeline System, Limited Partnership. In May 2009, Spectra Energy Partners acquired all of the ownership interests of NOARK Pipeline System, Limited Partnership (NOARK) from Atlas Pipeline Partners, L.P. (Atlas) for approximately $295 million in cash. See Note 3 for further discussion.

Sale of Spectra Energy Partners Common Units. In the second quarter of 2009, Spectra Energy Partners issued 9.8 million common units to the public, representing limited partner interests, and 0.2 million general partner units to Spectra Energy in connection with the refinancing of the purchase of NOARK, resulting in net proceeds of $212 million and a reduction of our ownership interest in Spectra Energy Partners from 84% to 74%. The net proceeds were comprised of $208 million for the common units and $4 million for the general partner units.

In connection with the sale of the partner units and the dilution of our ownership interest in Spectra Energy Partners, a $40 million gain ($25 million net of tax) to Additional Paid-in Capital and a $168 million increase in Equity Noncontrolling Interests were recorded on the Consolidated Balance Sheet in 2009 .

3. Acquisitions and Dispositions

Acquisitions. We consolidate assets and liabilities from acquisitions as of the purchase date, and include 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 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 May 2009, Spectra Energy Partners acquired all of the ownership interests of NOARK from Atlas for approximately $295 million in cash. NOARK s assets consisted of 100% ownership interests in Ozark Gas Transmission, L.L.C. (Ozark Gas Transmission), a 565-mile Federal Energy Regulatory Commission (FERC) regulated interstate natural gas transmission system, and Ozark Gas Gathering, L.L.C., a 365-mile, fee-based, state-regulated natural gas gathering system. The transaction was initially funded by Spectra Energy Partners with $218 million drawn on its bank credit facility, $70 million borrowed under a credit facility with Spectra

Energy that was created for the sole purpose of funding a portion of this acquisition, and $7 million of cash on hand. This transaction was partially refinanced by Spectra Energy Partners in the second quarter of 2009 through the issuance of units as discussed in Note 2. Funds from the sale of the partner units were used by Spectra Energy Partners to repay the $70 million owed to Spectra Energy and $142 million of the amount drawn on the Spectra Energy Partners bank credit facility. Effective with the repayment to Spectra Energy, the credit facility with Spectra Energy was terminated.

The following table summarizes the fair values of the NOARK assets acquired and liabilities assumed:

	Purchase Price Allocation (in millions)
Purchase price	$ 295
Current assets	7
Property, plant and equipment, net	139
Regulatory assets and deferred debits	5
Current liabilities	(5)
Deferred credits and other liabilities	(1)
Total assets acquired/liabilities assumed	145
Goodwill	$ 150

In 2008, we acquired the 24.4 million units of the Spectra Energy Income Fund (Income Fund) that were held by non-affiliated holders for 279 million Canadian dollars (approximately $274 million). We now own 100% of the Canadian Midstream operations. Prior to the acquisition, the Income Fund indirectly held 54% of our consolidated Canadian Midstream operations and we indirectly held the remaining 46%. The transaction, primarily driven by changes in Canadian federal tax rules as related to income trusts, was accounted for as a step acquisition, using the purchase method of accounting. Equity Noncontrolling Interests decreased approximately $208 million as a result of the transaction.

Pro forma results of operations reflecting the acquisitions of NOARK (part of the U.S. Transmission segment) and the units of the Income Fund (part of the Western Canada Transmission & Processing segment), as if those transactions had occurred as of the beginning of the periods presented in this report do not materially differ from actual reported results.

Dispositions. In 2008, Spectra Energy sold Saltville and the P-25 pipeline to Spectra Energy Partners for $107 million. See Note 2 for further discussion. Also in 2008, we sold our interests in certain natural gas gathering and processing facilities. See Note 7 for further discussion.

4. Business Segments

We manage our business in four reportable segments: U.S. Transmission, Distribution, Western Canada Transmission & Processing and Field Services. The remainder of our 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.

Our chief operating decision maker regularly reviews financial information about each of these segments in deciding how to allocate resources and evaluate performance. There is no aggregation within our defined business segments.

U.S. Transmission provides transportation and storage of natural gas for customers in various regions of the northeastern 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 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. These services are provided by Union Gas Limited (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 NGLs 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 BC Pipeline, BC Field Services, and the NGL marketing and Canadian Midstream businesses. BC Pipeline s and BC 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 us and 50% by ConocoPhillips. DCP Midstream gathers raw natural gas through gathering systems located in nine major natural gas producing regions: Mid-Continent, Rocky Mountain, East Texas-North Louisiana, Barnett Shale, Gulf Coast, South Texas, Central Texas, Antrim Shale and Permian Basin.

Our 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 less noncontrolling interests related to those earnings.

On a segment basis, EBIT represents earnings from continuing operations (both operating and non-operating) before interest and taxes, net of noncontrolling interests related to those earnings. Cash, cash equivalents and short-term investments are managed centrally, 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.

Business Segment Data

	Unaffiliated Revenues	Intersegment Revenues	Total Revenues(a)	Segment EBIT/ Consolidated Earnings from Continuing Operations before Income Taxes(a) (in millions)	Depreciation and Amortization(a)	Capital and Investment Expenditures(a)	Segment Assets
2009							
U.S. Transmission	$ 1,683	$ 7	$ 1,690	$ 894	$ 246	$ 432(b)	$ 9,904
Distribution	1,745		1,745	336	172	224	5,023
Western Canada Transmission & Processing	1,115		1,115	343	144	353	4,420
Field Services				296			1,053
Total reportable segments	4,543	7	4,550	1,869	562	1,009	20,400
Other	9	38	47	(74)	22	32	3,753
Eliminations		(45)	(45)				(74)
Interest expense				(610)			
Interest income and other(c)				86			
Total consolidated	$ 4,552	$	$ 4,552	$ 1,271	$ 584	$ 1,041	$ 24,079
2008							
U.S. Transmission	$ 1,595	$ 5	$ 1,600	$ 844	$ 232	$ 1,400	$ 9,636
Distribution	1,991		1,991	353	175	373	4,505
Western Canada Transmission & Processing	1,482		1,482	398	147	222(d)	3,709
Field Services				716			858
Total reportable segments	5,068	5	5,073	2,311	554	1,995	18,708
Other	6	39	45	(78)	15	35	3,460
Eliminations		(44)	(44)				(244)
Interest expense				(636)			
Interest income and other(c)				91			
Total consolidated	$ 5,074	$	$ 5,074	$ 1,688	$ 569	$ 2,030	$ 21,924
2007							
U.S. Transmission	$ 1,535	$ 5	$ 1,540	$ 894	$ 217	$ 898	
Distribution	1,899		1,899	322	162	369	
Western Canada Transmission & Processing	1,266		1,266	359	135	195	
Field Services				533			
Total reportable segments	4,700	5	4,705	2,108	514	1,462	
Other	4	27	31	(112)	4	39	
Eliminations		(32)	(32)				
Interest expense				(633)			
Interest income and other(c)				79			
Total consolidated	$ 4,704	$	$ 4,704	$ 1,442	$ 518	$ 1,501	

(a) Excludes amounts associated with entities included in discontinued operations.
(b) Excludes the $295 million acquisition of NOARK.
(c) Includes foreign currency transaction gains and losses and the add-back of noncontrolling interests related to segment EBIT.
(d) Excludes the $274 million acquisition of units of the Income Fund.

Geographic Data

	U.S.	Canada (in millions)	Consolidated
2009			
Consolidated revenues(a)	$ 1,562	$ 2,990	$ 4,552
Consolidated long-lived assets	8,418	12,001	20,419
2008			
Consolidated revenues(a)	1,423	3,651	5,074
Consolidated long-lived assets	7,984	10,096	18,080
2007			
Consolidated revenues(a)	1,393	3,311	4,704

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

5. Regulatory Matters

Regulatory Assets and Liabilities. We record 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, 2009	December 31, 2008	Recovery/ Refund Period Ends
	(in millions)		
Regulatory Assets(a)(b)			
Net regulatory asset related to income taxes(c)	$ 784	$ 732	(d)
Project costs	33	35	2024
Vacation accrual	14	12	2010
Deferred debt expense/premium(e)	57	60	(d)
Environmental clean-up costs	6	6	2017
Gas in storage (included in Inventory)	35	33	2010
Gas purchase costs (included in Other Current Assets)	11	14	2010
Other	24	17	(f)
Total Regulatory Assets	$ 964	$ 909	
Regulatory Liabilities(b)			
Removal costs(e)(g)	$ 389	$ 343	(h)
Gas purchase costs(i)	185	15	2010
Pipeline rate credit(g)	32	33	(d)
Storage and transportation liability(i)	19	27	2010
Earnings sharing liability(i)	4	14	2010
Account rebates(i)	18		(f)
Other(g)	31	20	2010
Total Regulatory Liabilities	$ 678	$ 452	

(a) Included in Regulatory Assets and Deferred Debits unless otherwise noted.
(b) All regulatory assets and liabilities are excluded from rate base unless otherwise noted.
(c) All amounts are expected to be included in future rate filings.
(d) Recovery/refund is over the life of the associated asset or liability.
(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 as the associated assets are retired.
(i) Included in Other Current Liabilities.

Rate Related Information

Maritimes & Northeast Pipeline, L.L.C. (M&N LLC). On July 1, 2009, M&N LLC filed a rate case with the FERC. The rate case includes the impact of the Phase IV expansion facilities that went into service January 15, 2009 and would result in lower recourse rates. The lower recourse rates would not impact the rates negotiated with customers for service, which are charged to customers for over 90% of M&N LLC s capacity.

Maritimes & Northeast Pipeline Limited Partnership (M&N LP). During 2008, M&N LP operated under an NEB-approved toll settlement that expired December 31, 2008. M&N LP obtained approval to operate under interim rates, effective January 1, 2009, that were set to equal the 2008 rates. The final 2009 toll settlement rates were approved by the NEB in April 2009. M&N LP implemented the new rates on a prospective basis effective May 1, 2009 such that the total tolls charged during 2009 result in revenues equal to those had the new 2009 rates been in effect for the entire year.

Algonquin Gas Transmission, LLC (Algonquin). In 2005, Algonquin filed and the FERC accepted new negotiated rate agreements with the Algonquin customers that include a rate moratorium provision through December 2008. Algonquin and its customers have agreed to extend the previously agreed rates through October 2010.

Gulfstream Natural Gas System, L.L.C. Gulfstream operates under rates approved by FERC in 2007. 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 placed into effect new rates in November 2005 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.

Ozark Gas Transmission. Ozark Gas Transmission operates under rates established as a result of an uncontested settlement agreement with customers approved by FERC in 2000.

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.

Southeast Supply Header, LLC (SESH). SESH operates under rates approved by FERC in August 2008. That order required SESH to file a Cost and Revenue Study at the end of three years of operations. The projected filing date would be the summer of 2011.

Union Gas. The OEB issued a decision under the incentive regulation framework in January 2009 providing for slight increases in rates for Union Gas small-volume customers and slight decreases for large-volume customers. Beginning April 1, 2009, the new rates were retroactively applied to January 1, 2009.

The incentive regulation framework establishes new rates at the beginning of each year through the use of a pricing formula rather than through the examination of revenue and cost forecasts. The allowed return on equity (ROE) for Union Gas is formula-based and is periodically established by the OEB. The established ROE for 2008 will remain unchanged throughout the five-year incentive regulation period (2008-2012). The incentive regulation framework initially included a provision for a review of the pricing mechanism contained in that framework. That review was triggered if there was a variance of 300 basis points or more between Union Gas actual utility ROE as normalized for weather and the utility ROE determined by the OEB.

In the second quarter of 2009, we recorded an $11 million charge to Operating Revenues Distribution of Natural Gas in the Consolidated Statement of Operations as a result of a settlement with Union Gas stakeholders in June 2009 that was subsequently approved by the OEB. The settlement preserves the incentive regulation framework and replaces the provision for a review of the framework with a 90/10 sharing mechanism, in favor of customers, for any utility earnings of 300 basis points or more above the benchmark utility ROE for the year and is retroactive to 2008. The $11 million charge represents the adjustment to credit customers with 90% of Union Gas 2008 utility earnings that exceeded the 2008 benchmark utility ROE by 300 basis points.

In September 2009, Union Gas filed an application with the OEB seeking approval of 2010 regulated distribution, storage and transmission rates, determined pursuant to the incentive regulation framework. The application proposes a delivery rate increase of less than 1% for a typical residential customer in Union Gas service territory. The OEB approved the application, as filed, in November 2009.

In 2006, Union Gas received a decision from the OEB on the regulation of rates for gas storage services in Ontario (the Storage Forbearance Decision). 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. The Storage Forbearance Decision requires Union Gas to continue to share long-term storage margins with ratepayers over a four-year phase-out period that started in 2007.

In 2008, Union Gas applied to the OEB for the annual disposition of its 2007 non-commodity deferral account balances. The OEB issued its decision on this application in June 2008 finding that Union Gas should share revenue on all long-term storage contracts. Union Gas had previously interpreted the Storage Forbearance Decision to apply only to those contracts that were in existence as of the date of the Storage Forbearance Decision. Union Gas appealed this decision, and the OEB denied the appeal. In 2008, Union Gas recorded a $15 million charge to Transportation, Storage and Processing of Natural Gas operating revenues in the Consolidated Statement of Operations as a result of the June 2008 decision.

In December 2009, the OEB issued its policy report on the Cost of Capital for Ontario s Regulated Utilities. In that report, the OEB determined that Union Gas utility ROE should be increased by approximately 125 basis points. Union Gas is currently assessing how and when that increase might be implemented in light of its multi-year incentive regulation parameters, and is unable at this time to determine the impact.

Union Gas has regulatory assets of $154 million as of December 31, 2009 and $164 million as of December 31, 2008 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 those assets.

Union Gas has removal costs of $378 million as of December 31, 2009 and $330 million as of December 31, 2008. These regulatory liabilities represent collections from customers under approved rates for future removal activities that are expected to occur associated with the regulated facilities.

In addition, Union Gas has regulatory liabilities of $176 million as of December 31, 2009 and $15 million as of December 31, 2008 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 BC Field Services. In 2008, BC Pipeline and its customers reached an NEB-approved settlement agreement regarding the determination of final tolls for transmission services for 2008, 2009 and 2010. Rates per the new agreement did not significantly change from prior rates.

The BC Field Services gathering and processing facilities currently operate under a Framework for Light-Handed Regulation (the Framework) approved by the NEB. The Framework established policies and guidelines which, among other things, permit the negotiation by BC Field Services of contracts for gathering and processing services with new and existing shippers. The Framework also provides that BC Field Services operations are responsible for the level of utilization of its gathering and processing facilities and, consequently, bears the opportunities and risks associated with that responsibility. BC Field Services tolls and other service conditions for gathering and processing services are subject to NEB oversight.

The BC Pipeline and BC Field Services businesses in Western Canada have regulatory assets of $525 million as of December 31, 2009 and $456 million as of December 31, 2008 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 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 BC Field Services regulatory assets, we take 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 the BC Pipeline and BC Field Services businesses. Based on current evaluation of these factors, we believe that recovery of these tax costs is probable over the periods described above.

We believe that the effects of the above matters will not have a material adverse effect on our future consolidated results of operations, financial position or cash flows.

6. Income Taxes

The following details the components of income tax expense:

	2009	2008 (in millions)	2007
Current income taxes			
Federal	$ 35	$ 240	$ 316
State	1	19	21
Foreign	145	78	32
Total current income taxes	181	337	369
Deferred income taxes			
Federal	207	108	(15)
State	17	6	4
Foreign	(52)	45	82
Total deferred income taxes	172	159	71
Income tax expense from continuing operations	353	496	440
Income tax expense from discontinued operations	1	3	10
Total income tax expense	$ 354	$ 499	$ 450

Earnings from Continuing Operations before Income Taxes

	2009	2008 (in millions)	2007
Domestic	$ 807	$ 1,128	$ 954
Foreign	464	560	488
Total earnings from continuing operations before income taxes	$ 1,271	$ 1,688	$ 1,442

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

	2009	2008 (in millions)	2007
Income tax expense, computed at the statutory rate of 35%	$ 445	$ 591	$ 505
State income tax, net of federal income tax effect	12	9	16
Tax differential on foreign earnings	(62)	(62)	(45)
Domestic production activities deduction	(4)	(13)	(11)
Noncontrolling interests	(26)	(22)	(22)
Other items, net	(12)	(7)	(3)
Total income tax expense from continuing operations-controlling interests	$ 353	$ 496	$ 440
Effective tax rate	27.8%	29.4%	30.5%

Net Deferred Income Tax Liability Components

	December 31, 2009	 2008
	(in millions)	
Deferred credits and other liabilities	$ 183	$ 183
Federal effects of uncertain tax benefits	15	18
Other	57	12
Total deferred income tax assets	255	213
Valuation allowance	(19)	(12)
Net deferred income tax assets	236	201
Investments and other assets	(1,044)	(928)
Accelerated depreciation rates	(2,198)	(1,962)
Regulatory assets and deferred debits	(112)	(126)
Total deferred income tax liabilities	(3,354)	(3,016)
Total net deferred income tax liabilities	$ (3,118)	$ (2,815)

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

	December 31, 2009	December 31, 2008
	(in millions)	
Other current assets	$ 59	$ 28
Other current liabilities	(64)	(54)
Deferred credits and other liabilities	(3,113)	(2,789)
Total net deferred income tax liabilities	$ (3,118)	$ (2,815)

At December 31, 2009, we had an unused state net operating loss carryforward of $125 million that expires beginning in 2012. The tax benefits associated with the state net operating losses of $9 million are expected to be fully recoverable within the applicable statutory expiration periods.

At December 31, 2009, we had a foreign net operating loss carryforward of $50 million that expires at various times beginning in 2027 and a foreign capital loss carryforward of $147 million with an indefinite expiration period. We have a valuation allowance of $19 million at December 31, 2009 and $12 million at December 31, 2008 against the deferred tax asset related to the foreign capital loss carryforward. The increase in the valuation allowance is due to additional net capital losses and changes in foreign currency exchange rates.

Reconciliation of Gross Unrecognized Income Tax Benefits

	2009	2008	2007
		(in millions)	
Balance at January 1	$ 76	$ 86	$ 75
Increases related to prior year tax positions	11	10	3
Decreases related to prior year tax positions	(29)	(10)	(5)
Increases related to current year tax positions	2	7	16
Settlements	(1)		(2)
Reductions due to lapse of statute of limitations	(3)	(10)	(6)
Foreign currency translation	5	(7)	5
Balance at December 31	$ 61	$ 76	$ 86

Unrecognized tax benefits totaled $61 million at December 31, 2009. Of this, $66 million would reduce the annual effective tax rate if recognized on or after January 1, 2010.

We recorded a net decrease of $15 million in gross uncertain tax benefits during 2009. Of this, $14 million reduced income tax expense and $1 million was attributable to deferred tax liabilities and foreign currency exchange rate fluctuations.

We recognize potential accrued interest and penalties related to unrecognized tax benefits as interest expense and as other expense, respectively. We recognized interest income of $4 million in 2009 and interest expense of $4 million in 2008 and $7 million in 2007 related to unrecognized tax benefits. Accrued interest and penalties totaled $16 million at December 31, 2009 and $21 million at December 31, 2008.

Although uncertain, we believe it is reasonably possible that prior to December 31, 2010 the total amount of unrecognized tax benefits could decrease by approximately $12 million. The anticipated changes in unrecognized tax benefits relate to expiration of statutes of limitations.

Prior to January 1, 2007, we were 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, we indemnified Duke Energy for Spectra Energy s share of taxes on such returns. Accordingly, obligations of $43 million at December 31, 2009 and $39 million at December 31, 2008 for uncertain federal and state income tax positions, including interest and penalties, for periods in which we were 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 Sheets. We have 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.

We remain subject to examination for Canada income tax return filings for years 2002 through 2007 and U.S. income tax return filings for 2007 and 2008.

Cumulative undistributed earnings of our foreign subsidiaries at December 31, 2009 totaled $153 million for which we have not provided U.S. deferred income taxes and foreign withholding taxes since we intend to permanently reinvest such earnings in our foreign operations. Unrecognized U.S. deferred income taxes and foreign withholding taxes on these undistributed earnings are expected to be $55 million.

7. Discontinued Operations

The following table summarizes results classified as Income From Discontinued Operations, Net of Tax in the accompanying Consolidated Statements of Operations:

	Operating Revenues	Pre-tax Earnings	Income Tax Expense	Income From Discontinued Operations, Net of Tax
			(in millions)	
2009				
Western Canada Transmission & Processing	$ 2	$ 3	$ 1	$ 2
Other	171	3		3
Total consolidated	$ 173	$ 6	$ 1	$ 5
2008				
Western Canada Transmission & Processing	$ 24	$ 2	$	$ 2
Other	86			
Total consolidated	$ 110	$ 2	$	$ 2
2007				
Western Canada Transmission & Processing	$ 38	$ 16	$ 4	$ 12
Other	1	20	7	13
Total consolidated	$ 39	$ 36	$ 11	$ 25

The following significant transactions, the effects of which are included in Income From Discontinued Operations, Net of Tax on the Consolidated Statements of Operations, occurred during 2008 and 2007.

2008

In 2008, we closed on the sale of our interests in the Nevis and Brazeau River natural gas gathering and processing facilities, which were part of the Western Canada Transmission & Processing segment. Total proceeds from the sale were 129 million Canadian dollars (approximately $104 million) and we recognized a $2 million pre-tax and after-tax gain on the sale.

In 2007, Spectra Energy LNG Sales, Inc. (Spectra Energy LNG) reached a settlement agreement related to an arbitration proceeding regarding Spectra Energy LNG s claims for the period prior to May 2002 under certain liquefied natural gas (LNG) transportation contracts with Sonatrach and Sonatrading Amsterdam B.V. (Sonatrach). See 2007 below for impacts of this settlement. In June 2008, the parties entered into a settlement agreement under which Spectra Energy LNG s claims for the period after May 2002 were satisfied pursuant to commercial transactions involving the purchase of propane from Sonatrach. We entered into associated agreements with an affiliate of DCP Midstream and another party for the sale of these propane volumes. Net purchases and sales of propane under these arrangements are reflected as Other discontinued operations. Spectra Energy LNG was one of the entities contributed by us to Duke Energy in 2006 in connection with our spin-off from Duke Energy that was subsequently reflected as discontinued operations.

2007

In 2007, $18 million of income ($11 million net of tax) was recorded related to the settlement of the Sonatrach proceeding described above.

8. Earnings per Common Share

Basic EPS is computed by dividing net income from controlling interests by the weighted-average number of common shares outstanding during the period. Diluted EPS is computed by dividing net income from controlling interests 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 our basic and diluted EPS calculations:

	2009	2008	2007
	(in millions, except per-share amounts)		
Income from continuing operations, net of tax controlling interests	$ 843	$ 1,129	$ 940
Income from discontinued operations, net of tax controlling interests	5		17
Net income controlling interests	$ 848	$ 1,129	$ 957
Weighted average common shares, outstanding			
Basic	642	622	632
Diluted	643	624	635
Basic earnings per common share			
Continuing operations	$ 1.31	$ 1.82	$ 1.48
Discontinued operations, net of tax	0.01		0.03
Total basic earnings per common share	$ 1.32	$ 1.82	$ 1.51
Diluted earnings per common share			
Continuing operations	$ 1.31	$ 1.81	$ 1.48
Discontinued operations, net of tax	0.01		0.03
Total diluted earnings per common share	$ 1.32	$ 1.81	$ 1.51

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 ten million shares for both 2009 and 2008, and 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 shares during these periods or performance measures related to the awards had not yet been met.

9. Marketable Securities

At December 31, 2009, we had no short-term and $7 million of long-term investments. At December 31, 2008, we had $13 million short-term and $53 million of long-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.

Interest income totaled $4 million in 2009, $22 million in 2008 and $26 million in 2007, and is included in Other Income and Expenses, Net on the Consolidated Statements of Operations.

Short-term investments. In 2009, we redeemed $13 million of short-term investments and had no purchases. In 2008, we transferred $13 million in investments associated with captive insurance from restricted reserves, and had no other sales or purchases. There were no purchases or sales of short-term investments in 2007.

During 2008, the U.S. Transmission segment received shares of stock as consideration for a customer bankruptcy settlement and recorded a gain based on the quoted market price on the date of receipt of $31 million ($21 million after tax) which is reflected in Gains on Sales of Other Assets and Other, Net in the Consolidated Statements of Operations. The stock was subsequently sold in 2008, resulting in net proceeds of $27 million, reflected in Cash Flows from Operating Activities on the Consolidated Statements of Cash Flows, and a loss of $4 million recorded as Other Income and Expenses, Net.

Long-term investments. In 2007, we invested a portion of the proceeds from Spectra Energy Partners IPO in financial instruments, including money market and debt securities that frequently had stated maturities of 20 years or more. These investments, which totaled $32 million as of December 31, 2008, were pledged as collateral against Spectra Energy Partners term loan and were classified as Investments and Other Assets Other on the Consolidated Balance Sheet. There was no term loan outstanding or investments pledged as collateral at December 31, 2009. We received proceeds on sales of $32 million of these investments in 2009. We purchased $1,132 million and received proceeds on sales of $1,256 million of these investments in 2008, and purchased $1,439 million and received proceeds on sales of $1,284 million of these investments in 2007.

On January 2, 2007, Duke Energy distributed to us 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 us. These securities, which are generally comprised of short-term debt instruments, are classified as long-term since they are restricted for insurance reserves. We purchased $1 million and received proceeds on sales of $14 million of other long-term investments in 2009 within the captive insurance portfolio. We purchased $1 million and received proceeds on sales of $36 million in 2008, and purchased $93 million and received proceeds on sales of $121 million in 2007.

The estimated fair values of long-term investments, classified as available-for-sale, are as follows:

	December 31, 2009			December 31, 2008		
	Gross Unrealized Holding Gains	Gross Unrealized Holding Losses	Estimated Fair Value	Gross Unrealized Holding Gains	Gross Unrealized Holding Losses	Estimated Fair Value
			(in millions)			
Corporate debt securities	$	$	$	$	$	$ 25
U.S. Government securities			7			21
Other						7
Total long-term investments	$	$	$ 7	$	$	$ 53

The average contractual maturity of the above securities was either less than one year at December 31, 2009 and 2008 or the security had been sold as of the date of this report.

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

Investments in affiliates for which we are not the primary beneficiary, but over which we have significant influence, are accounted for using the equity method. As of December 31, 2009 and 2008, the carrying amount of investments in affiliates approximated the amount of underlying equity in net assets. We received distributions from our equity investments of $359 million in 2009, $995 million in 2008 and $656 million in 2007. Cumulative undistributed earnings of unconsolidated affiliates totaled $192 million at December 31, 2009 and $58 million at December 31, 2008.

U.S. Transmission. As of December 31, 2009, investments primarily include 50% interests in Gulfstream, SESH, and Steckman Ridge, LP (Steckman Ridge). Gulfstream is an interstate natural gas pipeline that extends from Mississippi and Alabama across the Gulf of Mexico to Florida. SESH, which was placed in service in the second half of 2008, is an interstate natural gas pipeline that extends from northeast Louisiana to Mobile County, Alabama where it connects to the Gulfstream system. Steckman Ridge, which was placed into service in the first half of 2009, is a storage project located in Bedford County, Pennsylvania.

In 2007, we and CenterPoint Energy Gas Transmission Company (the co-owner of SESH) 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 its pipeline facilities. In 2009, $137 million of the outstanding loan from us was re-characterized as a capital infusion to SESH. In addition, we received $186 million from SESH, recorded as Receipt From Affiliate Repayment of Loan on the Consolidated Statement of Cash Flows, representing full repayment of the remaining balance of the outstanding loan receivable. A portion of these funds were from the proceeds of a debt issuance by SESH. The loan receivable from SESH, including accrued interest, totaled $327 million at December 31, 2008. We recorded interest income on the SESH loan of $4 million in 2009, $10 million in 2008 and $2 million in 2007.

In 2009, we received a $148 million special distribution from Gulfstream from the proceeds of a debt issuance by Gulfstream, of which $144 million was classified as Cash Flows from Investing Activities Distributions Received From Unconsolidated Affiliates on the Consolidated Statement of Cash Flows.

We have made loans to Steckman Ridge in connection with the construction of its storage facilities. The loans carry market-based interest rates and are due the earlier of December 31, 2017 or coincident with the closing of any long-term financings by Steckman Ridge. The loan receivable from Steckman Ridge, including accrued interest, totaled $71 million at December 31, 2009 and $45 million at December 31, 2008. We recorded interest income on the Steckman Ridge loan of $1 million in 2009, $1 million in 2008 and less than $1 million in 2007.

We are a 50% equity partner and operator for Islander East Pipeline Company, L.L.C. (Islander East), an entity formed to develop and own a pipeline that would connect natural gas supplies to markets on Long Island, New York. Algonquin, a wholly owned subsidiary, also had a companion project, the AGT Islander East Lease Project. During 2008, Islander East was denied a petition for certiorari by the U.S. Supreme Court with respect to a water quality certificate that had been denied by the State of Connecticut.

As Islander East considered various project path alternatives in 2008 for connecting natural gas supplies to Long Island, it became evident that credit and recessionary pressures would likely result in significant further delay of any alternative project ultimately agreed upon with the appropriate customers. Triggered by fourth quarter 2008 legal and economic events, capitalized development costs associated with Islander East were evaluated as to probability of recovery. We evaluated the likelihood of various project outcomes in order to estimate the fair value of recoverable costs. This analysis resulted in an impairment charge in the fourth quarter of 2008 of $44 million before tax ($12 million in Operating, Maintenance and Other expenses and $32 million in Equity in Earnings of Unconsolidated Affiliates), representing our share of impaired assets associated with Islander East.

Field Services. Our most significant investment in unconsolidated affiliates is our 50% investment in DCP Midstream which is accounted for under the equity method of accounting. DCP Midstream is a limited liability company which is a pass-through entity for U.S. 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 attributable to members interests does not include income taxes for earnings which are passed through to the members based upon their ownership percentage. We recognize the tax effects of our share of DCP Midstream s pass-through earnings in Income Tax Expense from Continuing Operations in the accompanying Consolidated Statements of Operations.

In 2005, DCP Midstream formed DCP Midstream Partners, LP (DCP Partners), a master limited partnership and also in 2005, DCP Partners completed its IPO. As a result of the adoption of SFAS No. 160 (now ASC 810-10-65) on January 1, 2009, DCP Midstream reclassified to equity certain deferred gains on sales of common units in DCP Partners. Our proportionate 50% share, totaling $135 million, was recorded in Equity in Earnings of Unconsolidated Affiliates in the Consolidated Statement of Operations in the first quarter of 2009.

Investments in and Loans to Unconsolidated Affiliates

	December 31, 2009			December 31, 2008		
	Domestic	International	Total	Domestic	International	Total
			(in millions)			
U.S. Transmission	$ 969	$	$ 969	$ 1,281	$	$ 1,281
Western Canada Transmission & Processing		14	14		13	13
Field Services	1,018		1,018	858		858
Total	$ 1,987	$ 14	$ 2,001	$ 2,139	$ 13	$ 2,152

Equity in Earnings of Unconsolidated Affiliates

	2009			2008			2007		
	Domestic	International	Total	Domestic	International	Total	Domestic	International	Total
					(in millions)				
U.S. Transmission	$ 74	$	$ 74	$ 59	$	$ 59	$ 62	$	$ 62
Western Canada Transmission & Processing		(1)	(1)		4	4		2	2
Field Services	296		296	715		715	532		532
Total	$ 370	$ (1)	$ 369	$ 774	$ 4	$ 778	$ 594	$ 2	$ 596

Summarized Combined Financial Information of Unconsolidated Affiliates (Presented at 100%)

Statements of Operations

	2009			2008			2007		
	DCP Midstream	Other	Total	DCP Midstream	Other	Total	DCP Midstream	Other	Total
					(in millions)				
Operating revenues	$ 8,560	$ 446	$ 9,006	$ 16,398	$ 330	$ 16,728	$ 13,154	$ 272	$ 13,426
Operating expenses	8,026	199	8,225	14,704	222	14,926	11,959	117	12,076
Operating income	534	247	781	1,694	108	1,802	1,195	155	1,350
Net income	306	168	474	1,519	102	1,621	1,059	124	1,183
Net income attributable to members interests	322	168	490	1,431	102	1,533	1,074	124	1,198

Balance Sheets

	December 31, 2009			December 31, 2008		
	DCP Midstream	Other	Total	DCP Midstream	Other	Total
			(in millions)			
Current assets	$ 1,809	$ 198	$ 2,007	$ 1,665	$ 236	$ 1,901
Non-current assets	6,183	3,572	9,755	6,127	3,513	9,640
Current liabilities	(2,534)	(65)	(2,599)	(1,771)	(744)	(2,515)
Non-current liabilities	(3,140)	(1,891)	(5,031)	(4,059)	(1,161)	(5,220)
Equity total	2,318	1,814	4,132	1,962	1,844	3,806
Equity noncontrolling interests	(315)		(315)	(312)		(312)
Equity controlling interests	$ 2,003	$ 1,814	$ 3,817	$ 1,650	$ 1,844	$ 3,494

Related Party Transactions

DCP Midstream. DCP Midstream processes certain of our customers gas to meet gas quality specifications in order to be transported on our system. DCP Midstream processes the gas and sells the NGLs that are extracted from the gas. A portion of the proceeds from those sales are retained by DCP Midstream and the balance is remitted to us. We received proceeds of $63 million in 2009, $121 million in 2008 and $112 million in 2007 from DCP Midstream related to those sales, classified as Other Operating Revenues.

As discussed in Note 7, we entered into a propane sales agreement with an affiliate of DCP Midstream in 2008. We recorded revenues of $98 million in 2009 and $49 million in 2008 associated with this agreement, classified within Income From Discontinued Operations, Net of Tax.

In addition to the above, we recorded other revenues from DCP Midstream and its affiliates totaling $7 million in both 2009 and 2008, and $9 million in 2007, primarily within Transportation, Storage and Processing of Natural Gas.

We had accounts receivable from DCP Midstream and its affiliates of $15 million at December 31, 2009 and $1 million at December 31, 2008. In addition, we had a distribution receivable from DCP Midstream of $36 million at December 31, 2009, recorded within Receivables on the Consolidated Balance Sheet. Total distributions received from DCP Midstream were $101 million in 2009, $930 million in 2008 and $618 million in 2007. Of these distributions, $101 million in 2009, $715 million in 2008 and $532 million in 2007 were recorded within Cash Flows from Operating Activities, and $215 million in 2008 and $86 million in 2007 were recorded within Cash Flows from Investing Activities.

Other. We provide certain administrative and other services to our equity investment operating entities. We recorded recoveries of costs from these affiliates of $24 million in 2009, $54 million in 2008 and $78 million in 2007. Outstanding receivables from these affiliates totaled $5 million at December 31, 2009 and $4 million at December 31, 2008.

See also Notes 3, 15 and 19 for additional related party information.

11. Goodwill

The following tables show the components and activity within goodwill:

	December 31, 2008	Increases(a) (in millions)	December 31, 2009
U.S. Transmission	$ 2,019	$ 372	$ 2,391
Distribution	727	104	831
Western Canada Transmission & Processing	635	91	726
Total consolidated	$ 3,381	$ 567	$ 3,948

	December 31, 2007	Decreases(b) (in millions)	December 31, 2008
U.S. Transmission	$ 2,334	$ (315)	$ 2,019
Distribution	874	(147)	727
Western Canada Transmission & Processing	740	(105)(c)	635
Total consolidated	$ 3,948	$ (567)	$ 3,381

(a) Increases consist of foreign currency translation and $150 million of goodwill at U.S. Transmission associated with the acquisition of NOARK. See Note 3 for further discussion.
(b) Decreases consist primarily of foreign currency translation.
(c) Includes $66 million of goodwill associated with the acquisition of additional units of the Income Fund. See Note 3 for further discussion.

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, 2009	December 31, 2008
	(in millions)	
U.S. Transmission	$ 1,781	$ 1,559
Distribution	828	725
Western Canada Transmission & Processing	690	603

No impairments of goodwill were recorded in 2009, 2008 or 2007. Based on the results of our annual impairment testing, the fair values of our reporting units with associated goodwill at December 31, 2009 significantly exceeded their carrying value. See Note 1 for discussion of goodwill impairment testing and a change in 2009 of the goodwill impairment test date.

12. Property, Plant and Equipment

	Estimated Useful Life (years)	December 31, 2009	2008
		(in millions)	
Plant			
Natural gas transmission	20 100	$ 11,302	$ 10,241
Natural gas distribution	25 60	2,484	2,026
Gathering and processing facilities	25 40	3,069	2,398
Storage	10 122	1,377	1,103
Other buildings and improvements	10 50	94	84
Equipment	3 40	389	329
Vehicles	2 20	94	86
Land and land rights	45 60	193	156
Construction in process		419	690
Other	4 82	539	456
Total property, plant and equipment		19,960	17,569
Total accumulated depreciation and amortization		(4,613)	(3,930)
Total net property, plant and equipment		$ 15,347	$ 13,639

We had no material capital leases at December 31, 2009 or 2008.

Almost 90% of our property, plant and equipment is regulated with estimated useful lives based on rates approved by the applicable regulatory authorities in the United States and Canada: the FERC, the NEB and the OEB. Composite weighted-average depreciation rates, including depreciation associated with businesses included in discontinued operations, were 3.17% for 2009, 3.29% for 2008 and 3.14% for 2007.

13. Asset Retirement Obligations

Our asset retirement obligations 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, we have determined that a significant portion of our assets have an indeterminate life, and as such, the fair value of the retirement obligation is not reasonably estimable. These assets include onshore and some offshore pipelines, and certain processing plants and distribution facilities, whose retirement dates will depend primarily on the various natural gas supply sources that connect to our systems and the ongoing demand for natural gas usage in the markets we serve. We expect these supply sources and market demands to continue for the foreseeable future, and, therefore, are not able to estimate a retirement date that would result in asset retirement obligations.

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 Changes in Asset Retirement Obligation Liabilities

	2009	2008
	(in millions)	
Balance at beginning of year	$ 84	$ 112
Accretion expense	6	6
Revisions in estimated cash flows	45	(7)
Asset dispositions		(8)
Foreign currency exchange impact	13	(19)
Liabilities settled	(5)	
Balance at end of year(a)	$ 143	$ 84

(a) Amounts included in Deferred Credits and Other Liabilities in the Consolidated Balance Sheets.

14. Debt and Credit Facilities

Summary of Debt and Related Terms

	Weighted-Average Interest Rate	Year Due	December 31, 2009	December 31, 2008
			(in millions)	
Unsecured debt	6.7%	2010 2038	$ 9,299	$ 9,154
Secured debt	5.9%	2010 2019	418	407
Capital leases				1
Commercial paper(a)	0.3%		162	428
Fair value hedge carrying value adjustment		2010 2018	51	68
Unamortized debt discount and premium, net			(12)	(11)
Total debt(b)			9,918	10,047
Current maturities of long-term debt			(809)	(821)
Short-term borrowings and commercial paper(c)			(162)	(936)
Total long-term debt			$ 8,947	$ 8,290

(a) The weighted-average days to maturity was 7 days as of December 31, 2009 and 11 days as of December 31, 2008.
(b) As of December 31, 2009 and 2008, respectively, $4,239 million and $3,766 million of debt were denominated in Canadian dollars.
(c) Weighted-average rates on outstanding short-term borrowings and commercial paper was 0.3% as of December 31, 2009 and 2.8% as of December 31, 2008.

In 2008, M&N LLC paid $288 million to retire its outstanding bonds and bank debt, and an additional $54 million early-extinguishment premium for the bonds. The payment of the premium, a regulatory asset, is presented within Cash Flows from Financing Activities Other on the Consolidated Statement of Cash Flows.

Secured Debt. Secured debt includes project financing for M&N LP. Ownership interests in M&N LP and certain of its accounts, revenues, business contracts and other assets are pledged as collateral. Secured debt at December 31, 2008 also included the term debt of Spectra Energy Partners which was collateralized by investment-grade securities.

Floating Rate Debt. Unsecured, secured and other debt included approximately $402 million of floating-rate debt as of December 31, 2009 and $1,339 million as of December 31, 2008. The weighted average interest rate of borrowings outstanding that contained floating rates was

0.5% at December 31, 2009 and 2.7% at December 31, 2008.

Annual Maturities

	December 31, 2009 (in millions)
2010	$ 809
2011	301
2012	772
2013	931
2014	1,167
Thereafter	5,776
Total long-term debt(a)	$ 9,756

(a) Excludes short-term borrowings and commercial paper of $162 million.

We have the ability under certain debt facilities to call and repay the obligations prior to scheduled maturities. Therefore, the actual timing of future cash repayments could be materially different than presented above.

Available Credit Facilities and Restrictive Debt Covenants

	Expiration Date	Credit Facilities Capacity	Outstanding at December 31, 2009 Commercial Paper	Revolving Credit	Letters of Credit	Total
			(in millions)			
Spectra Capital(a)						
Multi-year syndicated	2012	$ 1,500	$ 41	$	$ 27	$ 68
Westcoast(b)						
Multi-year syndicated	2011	190	84			84
364-day bilateral	2010	19			1	1
Union Gas(c)						
Multi-year syndicated	2012	475	37			37
364-day bilateral	2010	14			4	4
Spectra Energy Partners						
Multi-year syndicated	2012	500		240		240
Total		$ 2,698	$ 162	$ 240	$ 32	$ 434

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

(b) U.S. dollar equivalent at December 31, 2009. Two credit facilities, totaling 220 million Canadian dollars, each contain a covenant that requires the debt-to-total capitalization ratio to not exceed 75%.

(c) U.S. dollar equivalent at December 31, 2009. Two credit facilities, totaling 515 million Canadian dollars, each contain a covenant that requires the debt-to-total capitalization ratio to not exceed 75%. The multi-year syndicated facility 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.

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

Our credit agreements contain various financial and other covenants, including the maintenance of certain financial ratios. 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, 2009, we were in compliance with those covenants. In addition, our credit agreements allow for the 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. Our debt and credit agreements do not contain provisions that trigger an acceleration of indebtedness based solely on the occurrence of a material adverse change in our financial condition or results of operations.

As noted above, the terms of our Spectra Capital credit agreement require our consolidated debt-to-total capitalization ratio to be 65% or lower. As of December 31, 2009, this ratio was 56%. Approximately $5.3 billion of our equity (net assets) was considered restricted at December 31, 2009, representing the minimum amount of equity required to maintain the 65% consolidated debt-to-total capitalization ratio at December 31, 2009.

15. Preferred Stock of Subsidiaries

In connection with the acquisition of Westcoast in 2002, we assumed preferred shares at Westcoast and Union Gas. The preferred shares are generally not redeemable prior to specified redemption dates. On or after those dates, the shares may be redeemed, in whole or in part, for cash at the option of Westcoast and Union, as applicable. The shares are not subject to any sinking fund or mandatory redemption and are not convertible into any other securities of Westcoast or Union. As redemption of the shares is not solely within our control, we have classified the preferred stock of subsidiaries as temporary equity on our Consolidated Balance Sheets. Dividends are cumulative and payable quarterly, and are included in Net Income Noncontrolling Interests in the Consolidated Statements of Operations.

16. Fair Value Measurements

The following table presents, for each of the fair value hierarchy levels, assets and liabilities that are measured and recorded at fair value on a recurring basis:

		December 31, 2009			
Description	**Consolidated Balance Sheet Caption**	**Total**	**Level 1**	**Level 2**	**Level 3**
		(in millions)			
Money market funds	Cash and cash equivalents	$ 14	$ 14	$	$
Corporate debt securities	Cash and cash equivalents	50		50	
Derivative assets natural gas purchase contract	Investments and other assets other	15			15
Derivative assets interest rate swaps	Investments and other assets other	18		18	
Money market funds	Investments and other assets other	25	25		
Total Assets		$ 122	$ 39	$ 68	$ 15
Derivative liabilities interest rate swaps	Deferred credits and other liabilities regulatory and other	$ 17	$	$ 17	$
Total Liabilities		$ 17	$	$ 17	$

		December 31, 2008			
Description	**Consolidated Balance Sheet Caption**	**Total**	**Level 1**	**Level 2**	**Level 3**
		(in millions)			
Money market funds	Cash and cash equivalents	$ 60	$ 60	$	$
Debt securities issued by foreign governments	Cash and cash equivalents	6	6		
Corporate debt securities	Cash and cash equivalents	105		105	
Money market funds	Current assets other	13	13		
Derivative assets fair value hedge on long-term debt	Current assets other	13		13	
Money market funds	Investments and other assets other	51	51		
Corporate debt securities	Investments and other assets other	25		25	
Derivative assets natural gas purchase contract	Investments and other assets other	36			36
Derivative assets interest rate swaps	Investments and other assets other	53		53	
Total Assets		$ 362	$ 130	$ 196	$ 36
Derivative liabilities interest rate swaps		$ 23	$	$ 23	$

	Deferred credits and other liabilities and other	regulatory				
Total Liabilities			$ 23	$	$ 23	$

The following table reconciles Level 3 assets and liabilities, which are measured at fair value on a recurring basis using significant unobservable inputs:

	Short-Term Derivative Asset	Short-Term Derivative Liability	Long-Term Derivative Asset	Long-Term Derivative Liability
			(in millions)	
Fair value at December 31, 2007	$	$	$ 47	$ (21)
Total gains or losses (realized/unrealized):				
Included in earnings			(1)	(11)
Included in Investments and Other Assets Other				
Included in other comprehensive income		(5)	(10)	
Normal purchases and sales election				32
Purchases, issuances and settlements		5		
Fair value at December 31, 2008			36	
Total gains or losses (realized/unrealized):				
Included in earnings			(7)	
Included in Investments and Other Assets Other			2	
Included in other comprehensive income			(16)	
Fair value at December 31, 2009	$	$	$ 15	$
Total net losses for the period included in earnings (or changes in net assets) attributable to the changes in unrealized gains or losses relating to assets held at December 31, 2008	$	$	$ (1)	$ (11)
Total net losses for the period included in earnings (or changes in net assets) attributable to the changes in unrealized gains or losses relating to assets held at December 31, 2009	$	$	$ (6)	$

Level 1

Level 1 valuations represent quoted unadjusted prices for identical instruments in active markets.

Level 2 Valuation Techniques

Fair values of our financial instruments, primarily corporate debt securities that are actively traded in the secondary market, are determined based on market-based prices. These valuations may include inputs such as quoted market prices of the exact or similar instruments, broker or dealer quotations, or alternative pricing sources that may include models or matrix pricing tools, with reasonable levels of price transparency.

Level 3 Valuation Techniques

We do not have significant amounts of assets or liabilities measured and reported using level 3 valuation techniques, which include the use of pricing models, discounted cash flow methodologies or similar techniques where at least one significant model assumption or input is unobservable. Level 3 financial instruments also include those for which the determination of fair value requires significant management judgment or estimation.

Financial Instruments

The fair values of financial instruments that are recorded and carried at book value are summarized in the following table. Judgment is required in interpreting market data to develop the estimates of fair value. Estimates determined as of December 31, 2009 and 2008 are not necessarily indicative of the amounts we could have realized in current markets.

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	December 31,			
	2009		2008	
	Book Value	Approximate Fair Value	Book Value	Approximate Fair Value
	(in millions)			
Long-term receivables	$ 116	$ 118	$ 430	$ 427
Long-term debt, including current maturities	9,756	10,690	9,111	8,996

The fair values of long-term debt consider the terms of the related debt absent the impacts of derivative/hedging activities. The book values of long-term debt include the impacts of certain pay floating receive fixed interest rate swaps that are designated as fair value hedges.

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

During 2009 and 2008, there were no adjustments to assets and liabilities measured at fair value on a nonrecurring basis.

17. Commitments and Contingencies

General Insurance

We carry, either directly or through our captive insurance companies, insurance coverages consistent with companies engaged in similar commercial operations with similar type properties. Our insurance program includes (1) commercial general and excess liability insurance for liabilities to third parties for bodily injury and property damage resulting from our 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 our by-laws; and (5) property insurance, including machinery breakdown, on an all-risk-replacement valued basis, onshore business interruption and extra expense. All coverages are subject to certain deductibles, terms and conditions common for companies with similar types of operations.

Environmental

We are subject to various U.S. federal, state and local regulations, as well as Canadian national and provincial regulations, regarding air and water quality, hazardous and solid waste disposal and other environmental matters. These regulations can change from time to time, imposing new obligations on us.

Like others in the energy industry, we and our affiliates are responsible for environmental remediation at various contaminated sites. These include some properties that are part of our ongoing operations, sites formerly owned or used by us, 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 responsibility. If remediation activities involve statutory joint and several liability provisions, strict liability, or cost recovery or contribution actions, we or our affiliates could potentially be held responsible for contamination caused by other parties. In some instances, we 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 affiliated operations.

Included in Deferred Credits and Other Liabilities Regulatory and Other on the Consolidated Balance Sheets are accruals related to extended environmental-related activities totaling $16 million at December 31, 2009 and $17 million at December 31, 2008. These accruals represent provisions for costs associated with remediation activities at some of our current and former sites, as well as other environmental contingent liabilities.

Litigation

Duke Energy Retirement Cash Balance Plan. A class action lawsuit was filed in federal court in South Carolina in 2006 against Duke Energy and the Duke Energy Retirement Cash Balance Plan. A second similar class action was also filed in 2006 alleging similar claims and seeking to represent the same class of plaintiffs, but this second case was dismissed without prejudice, and only the first case has moved forward. Various causes of action were alleged in the class action lawsuit, 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, and various motions were thereafter filed by the parties, including plaintiffs motion to certify a class, Duke Energy s motion to dismiss, and cross motions for summary judgment filed by both the plaintiffs and Duke Energy. The Court issued a series of rulings in June 2008 denying the plaintiffs class certification motion, dismissing certain of the causes of action originally filed by plaintiffs and allowing other causes of action to proceed. As a result of these rulings, the plaintiffs re-filed a new Amended Class Action Complaint in June 2008 asserting and re-pleading the claims which the Court is allowing to proceed. Duke Energy filed a motion to dismiss in July 2008 requesting the dismissal of plaintiffs breach of fiduciary claims. Plaintiffs filed a new motion to certify a class action in August 2008 and Duke Energy has filed a response to this motion. The Court issued an Order on March 31, 2009 denying Duke Energy s motion to dismiss plaintiffs breach of fiduciary claims. A hearing on the issue of class certification of plaintiffs remaining claims was held on April 29, 2009. On September 4, 2009, the Court issued an Order granting class certification for plaintiffs remaining claims and denying certification of the plaintiffs breach of fiduciary claims.

In connection with the spin-off from Duke Energy in January 2007, we agreed to share with Duke Energy any liabilities or damages associated with this matter that relate to our employees that may be members of a plaintiff class if one is certified. At mediation, plaintiffs quantified their claims as being in excess of $150 million. It is not possible to predict with certainty the damages, if any, that we might incur in connection with this matter. However, based upon our current estimate of our employees that could be included in any plaintiff class, we believe that the final disposition of this matter will not have a material adverse effect on our consolidated results of operations, financial position or cash flows.

Other Litigation and Legal Proceedings. We 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. We have insurance coverage for certain of these losses should they be incurred. We believe that the final disposition of these proceedings will not have a material adverse effect on our consolidated results of operations, financial position or cash flows.

Legal costs related to the defense of loss contingencies are expensed as incurred. We had no material reserves recorded as of December 31, 2009 or 2008 related to litigation.

Other Commitments and Contingencies

See Note 18 for a discussion of guarantees and indemnifications.

Operating Lease Commitments

We lease assets in various areas of our operations. Consolidated rental expense for operating leases classified in Income From Continuing Operations was $47 million in 2009, $50 million in 2008 and $45 million in 2007, which is included in Operating, Maintenance and Other on the Consolidated Statements of Operations. Capital leases are of negligible amounts. 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. We had no material capital lease commitments at December 31, 2009.

	Long-term Operating Leases (in millions)
2010	$ 31
2011	31
2012	27
2013	24
2014	23
Thereafter	46
Total future minimum lease payments	$ 182

18. Guarantees and Indemnifications

We 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. We 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 having to honor our contingencies is largely dependent upon future operations of various subsidiaries, investees and other third parties, or the occurrence of certain future events.

We have 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 our spin-off from Duke Energy, certain guarantees that were previously issued by us were assigned to, or replaced by, Duke Energy as guarantor in 2006. For any remaining guarantees of other Duke Energy obligations, Duke Energy has indemnified us against any losses incurred under these guarantee arrangements. The maximum potential amount of future payments we could have been required to make under these performance guarantees as of December 31, 2009 was approximately $421 million, which has been indemnified by Duke Energy, as discussed above. One of our outstanding performance guarantees expires in 2028. The remaining guarantees have no contractual expiration.

We have also 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. D/FD is one of the entities transferred to Duke Energy in connection with our spin-off from Duke Energy. Substantially all of these guarantees have no contractual expiration and no stated maximum amount of future payments that we 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 us against any losses incurred under these guarantee arrangements. 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, 2009 was $55 million. These guarantees have no contractual expiration.

We have 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. Our 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. We are 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, 2009, the amounts recorded for the guarantees and indemnifications, described above, including the indemnifications by Duke Energy to us, are not material, both individually and in the aggregate.

19. Risk Management and Hedging Activities

We are exposed to the impact of market fluctuations in the prices of NGLs and natural gas purchased primarily as a result of 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. We are exposed to foreign currency risk from our Canadian operations. We employ established policies and procedures to manage our risks associated with these market fluctuations, which may include the use of forward physical transactions as well as other derivatives, primarily around interest rate exposures.

Our equity investment affiliate, DCP Midstream, also has risk exposures primarily associated with market prices of NGLs and natural gas. DCP Midstream manages these risks separate from Spectra Energy, and utilizes various risk management strategies, including the use of commodity derivatives.

Derivative Portfolio Carrying Value as of December 31, 2009

Asset/(Liability)	Maturity in 2010	Maturity in 2011	Maturity in 2012	Maturity in 2013 and Thereafter	Total Carrying Value
			(in millions)		
Hedging	$ 3	$ 4	$ 4	$ 22	$ 33
Undesignated				(17)	(17)
Total	$ 3	$ 4	$ 4	$ 5	$ 16

These amounts represent the combination of amounts presented as assets (liabilities) for unrealized gains and losses on mark-to-market and hedging transactions on our Consolidated Balance Sheet and do not include any derivative positions of DCP Midstream.

See Note 16 for information regarding the presentation of these derivative positions on our Consolidated Balance Sheets.

Commodity Cash Flow Hedges. Our Empress operations are exposed to market fluctuations in the prices of natural gas and NGLs related to natural gas processing and marketing activities. We closely monitor 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, forward contracts and options. There were no significant commodity cash flow hedge transactions during 2009, 2008 or 2007.

Interest Rate Hedges. Changes in interest rates expose us to risk as a result of our issuance of variable and fixed-rate debt and commercial paper. We manage our interest rate exposure by limiting our variable-rate exposures to percentages of total debt and by monitoring the effects of market changes in interest rates. We also enter 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.

For interest rate derivative instruments that are designated and qualify as fair value hedges, the gain or loss on the derivative as well as the offsetting loss or gain on the hedged item attributable to the hedged risk is recognized in the Consolidated Statements of Operations. There were no material amounts of gains or losses, either effective or ineffective, recognized in net income or other comprehensive income in 2009, 2008 or 2007.

In the first quarter of 2009, we settled all existing fixed-to-floating interest rate swaps on $848 million of long-term debt. Gains on the settlements, totaling $67 million, were recorded as follows in the Consolidated Balance Sheet: $5 million as a reduction to Interest Accrued, $21 million as a reduction to Current Maturities of Long-term Debt and $41 million as a reduction to Long-term Debt. The accumulated gains recorded as a basis adjustment to the associated debt will be amortized in Interest Expense over the lives of the associated debt.

As of December 31, 2009, we had interest rate hedges in place for various purposes. We are party to pay floating receive fixed interest rate swaps with a total notional amount of $750 million to hedge against declines in the fair value of our fixed-rate debt that arise as a result of changes in market interest rates. These swaps also allow us to transform a portion of the underlying cash flows related to our long-term fixed-rate debt into variable-rate debt in order to achieve our desired mix of fixed and variable-rate debt. We are also a party to forward starting pay fixed receive floating interest rate swaps with a total notional amount of $150 million to effectively lock in a fixed underlying interest rate in anticipation of the refinancing of a scheduled maturity. At Spectra Energy Partners, we have third-party pay fixed receive floating interest rate swaps with a total notional amount of $40 million to mitigate our exposure to variable interest rates on loans outstanding under the Spectra Energy Partners revolving credit facility.

Foreign Currency Hedges. We are exposed to foreign currency risk from investments and operations in Canada. 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. We may also use foreign currency derivatives, where possible, to manage risk related to foreign currency fluctuations. There were no significant foreign currency derivative transactions during 2009, 2008 or 2007. To monitor our currency exchange rate risks, we use sensitivity analysis, which measures the effect of devaluation of the Canadian dollar.

Credit Risk. Our 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 United States and Canada. We have 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 our overall credit risk in that risk factors can negatively affect the credit quality of the entire sector. Where exposed to credit risk, we analyze the counterparties financial condition prior to entering into an agreement, establish credit limits and monitor the appropriateness of those limits on an ongoing basis. We also obtain parental guarantees, cash or letters of credit from customers to provide credit support, where appropriate, based on our financial analysis of the customer and the regulatory or contractual terms and conditions applicable to each transaction.

Included in Other Current Liabilities and Deferred Credits and Other Liabilities Regulatory and Other are collateral liabilities of $88 million at December 31, 2009 and $121 million at December 31, 2008, which represent cash collateral posted by third parties with us.

20. Common Stock Issuance and Repurchases

On February 13, 2009, we issued 32.2 million shares of our common stock and received net proceeds of $448 million. We used the net proceeds to repay commercial paper as it matured. Borrowings from the commercial paper were used primarily for capital expenditures and for other general corporate purposes.

In 2008, our Board of Directors authorized a share repurchase program of up to $600 million under which purchases of our common stock under the program were made from time to time in the open market. During 2008, we repurchased a total of 22.3 million shares for $600 million, and the share repurchase program was concluded. The shares were retired upon repurchase and are presented as a reduction to Additional Paid-in Capital on the Consolidated Balance Sheet.

21. Effects of Changes in Noncontrolling Interests Ownership

The following table presents the effects of changes in our ownership interests in non-wholly owned consolidated subsidiaries:

	2009	2008	2007
		(in millions)	
Net Income Controlling Interests	$ 848	$ 1,129	$ 957
Increase in Additional Paid-in Capital resulting from sales of units of Spectra Energy Partners(a)	25		
Total Net Income Controlling Interests and changes in Equity Controlling Interests	$ 873	$ 1,129	$ 957

(a) See Note 2 for further discussion.

22. Stock-Based Compensation

In December 2006, we 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 us. 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 our 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 value of the shares on the date of grant. Related compensation expense is recognized over the requisite service period which is the same as the vesting period.

At the time of our spin-off from Duke Energy, 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 our employees and Duke 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.

The conversion of Duke Energy stock awards to Spectra Energy stock awards constituted a modification of those stock awards. However, 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 occurred when the holders were 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, we receive 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, we will recognize all associated expense and tax benefits relating to Duke Energy awards held by our employees. We recognize compensation expense, receive all cash proceeds and retain all tax benefits relating to Spectra Energy awards held by our employees.

We recorded pre-tax stock-based compensation expense in continuing operations as follows, the components of which are further described below:

	2009	2008	2007
		(in millions)	
Stock options	$	$ 3	$ 10
Stock appreciation rights(a)			(3)
Phantom stock	8	10	7
Performance awards	6	6	5
Total	$ 14	$ 19	$ 19

(a) 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 $3 million in 2009 and $7 million in both 2008 and 2007. We recognized tax benefits from stock-based compensation cost of approximately $3 million in additional paid in capital in 2009, $14 million in 2008 and $20 million in 2007.

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, 2008	12,847	$ 25	4.2	$ 6
Granted	20	19		
Exercised	(198)	13		
Forfeited or expired	(1,693)	24		
Outstanding at December 31, 2009	10,976	26	3.6	16
Exercisable at December 31, 2009	10,373	26	3.4	16
Options expected to vest	585	24	7.2	

In 2009, we granted 20,000 non-qualified stock options (fair value of less than $1 million, market price of $4.73 per share) to employees. We did not award non-qualified stock options to employees during 2008. In addition to the conversion of the Duke Energy stock options previously discussed, we granted 2,199,600 non-qualified stock options (fair value of $15 million, market price of $6.71 per 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 our 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. We issue 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.

Weighted-Average Assumptions for Option Pricing

The following weighted average assumptions were used for option pricing:

	2009	2008	2007
Risk-free rate of return	1.4%	n/a	4.4%
Expected life	7 years	n/a	7 years
Expected volatility	41%	n/a	29.5%
Expected dividend yield	5.3%	n/a	3.4%

n/a Indicates not applicable.

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 our annual dividend amount as a percentage of the average stock price at the time of grant.

Coincident with our spin-off, 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 was $1 million in 2009, $4 million in 2008 and $6 million in 2007. Cash received by us from options exercised was $3 million in 2009, $12 million in 2008 and $18 million in 2007. We recognized a nominal tax benefit in 2009, 2008 and 2007 since the options exercised were predominately held by Duke Energy employees. As of December 31, 2009, we expect to recognize less than $1 million of future compensation cost related to stock options over a weighted-average period of one year.

Stock Awards Activity

	Performance Awards		Phantom Stock Awards	
	Shares	Weighted Average Grant Date Fair Value	Shares	Weighted Average Grant Date Fair Value
	(shares in thousands)			
Outstanding at December 31, 2008	1,049	$ 24	1,138	$ 26
Granted	830	15	838	14
Vested	(537)	20	(192)	26
Forfeited	(117)	20	(21)	21
Outstanding at December 31, 2009	1,225	20	1,763	20
Awards expected to vest	1,198	19	1,725	20

Performance Awards

Stock-based performance awards 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 outstanding as of our spin-off date 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. 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 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 and Spectra Energy stock prices as the bases of measurement.

Under the Spectra Energy 2007 LTIP, we can also grant performance awards. The terms of the awards under Spectra s plan are substantially the same as performance awards under the Duke plan. Under the Spectra plan, the TSR of Spectra Energy common stock is compared to a revised group of peer companies. We granted 830,100 performance awards (fair value of $12 million) during 2009 and 497,500 performance awards (fair value of $15 million) during 2008. No performance awards were granted in 2007. The unvested and outstanding performance awards granted contain market conditions based on the TSR of Spectra Energy common stock relative to a pre-defined peer group (relative TSR). These awards are valued using the Monte Carlo valuation method.

Weighted-Average Assumptions for Performance Awards

	2009	2008
Risk-free rate of return	1.4%	2.3%
Expected life	3 years	3 years
Expected volatility Spectra Energy	41.2%	24.3%
Expected volatility peer group	20.8% 53.1%	14.2% 28.8%
Market index	28.5%	14.3%
Expected dividend yield		

The risk-free rate of return was determined based on a yield of three-year U.S. Treasury bonds on the grant date. The expected volatility was established based on historical volatility over three years using daily stock price observations. A shorter period was used if three years of data was not available. Because the award payout includes dividend equivalents, no dividend yield assumption is required.

The total fair value of shares vested was $11 million in 2009, $10 million in 2008 and $16 million in 2007. As of December 31, 2009, we expect to recognize $14 million of future compensation cost related to performance awards over a weighted-average period of less than two years.

Phantom Stock Awards

Stock-based phantom awards granted under the 2007 LTIP generally vest over three years. We awarded 837,900 phantom awards (fair value of $11 million) to our employees in 2009, 545,000 phantom awards (fair value of $13 million) in 2008 and 377,500 phantom awards (fair value of $10 million) in 2007. 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.

The total fair value of the shares vested was $5 million in 2009, $10 million in 2008 and $13 million in 2007. As of December 31, 2009, we expect to recognize $13 million of future compensation cost related to phantom stock awards over a weighted-average period of two years.

23. Employee Benefit Plans

Retirement Plans. Effective with our spin-off from Duke Energy in January 2007, we established a new qualified non-contributory defined benefit (DB) retirement plan for U.S. employees and new non-qualified plans for various executive retirement and savings 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. 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 us in 2007.

In addition, our Westcoast subsidiary maintains qualified and non-qualified contributory and non-contributory DB and defined contribution (DC) retirement plans covering substantially all employees of our 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. We also provide 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). We report our Canadian benefit plans separately due to differences in actuarial assumptions.

Our policy is to fund amounts for our U.S. qualified retirement plan on an actuarial basis to provide assets sufficient to meet benefits to be paid to plan participants. We did not make any contributions to our U.S. retirement plan in 2009, 2008 or 2007. We are considering making voluntary contributions to the plan in 2010, but have not made any decision at this time.

Our policy is to fund our DB retirement plans in Canada on an actuarial basis and in accordance with Canadian pension standards legislation in order to accumulate assets sufficient to meet benefit obligations. Contributions to the DC retirement plan are determined in accordance with the terms of the plan. We made contributions to the Canadian qualified DB plans of $56 million in 2009, $36 million in 2008 and $41 million in 2007. We also made contributions to the Canadian DC plan of $5 million in 2009, $4 million in 2008 and $5 million in 2007. We anticipate making contributions of approximately $60 million to the Canadian qualified DB plans in 2010.

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 eight years for the U.S. plan and 14 years for the Canadian plans. We determine 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.

Qualified Pension Plans

The following table provides the fair value of plan assets and the projected benefit obligation for the U.S. and Canadian plans:

Qualified Pension Plans Change in Projected Benefit Obligation and Change in Fair Value of Plan Assets

	U.S.		Canada	
	2009	2008	2009	2008
	(in millions)			
Change in Projected Benefit Obligation				
Projected benefit obligation, January 1	$ 461	$ 464	$ 570	$ 778
Service cost	9	9	12	16
Interest cost	27	27	39	38
Actuarial loss (gain)	24	2	71	(103)
Participant contributions			4	3
Benefits paid	(36)	(41)	(34)	(33)
Prior service cost			6	4
Foreign currency translation effect			97	(133)
Projected benefit obligation, December 31	485	461	765	570
Change in Fair Value of Plan Assets				
Plan assets, January 1	353	525	442	670
Actual return (loss) on plan assets	88	(131)	62	(133)
Benefits paid	(36)	(41)	(34)	(33)
Employer contributions			56	41
Plan participants contributions			4	3
Foreign currency translation effect			75	(106)
Plan assets, December 31	405	353	605	442
Net amount recognized(a)	$ (80)	$ (108)	$ (160)	$ (128)

(a) Recognized in Deferred Credits and Other Liabilities Regulatory and Other in the Consolidated Balance Sheets.

The plans noted above had accumulated benefit obligations in excess of plan assets. The accumulated benefit obligation for the U.S. plan was $464 million and $443 million at December 31, 2009 and 2008, respectively, and $696 million and $520 million at December 31, 2009 and 2008, respectively, for the Canadian plans.

Qualified Pension Plans Amounts Recognized in Accumulated Other Comprehensive Income

	U.S. December 31, 2009	U.S. December 31, 2008	Canada December 31, 2009	Canada December 31, 2008
	(in millions)			
Prior service costs	$ 1	$ 1	$ 14	$ 8
Net actuarial loss	178	214	247	182
Net reduction of AOCI	$ 179	$ 215	$ 261	$ 190

Qualified Pension Plans Components of Net Periodic Pension Costs

The following table shows the components of the pre-tax net periodic pension costs for our U.S. and Canadian retirement plans:

	U.S. 2009	U.S. 2008	U.S. 2007	Canada 2009	Canada 2008	Canada 2007
	(in millions)					
Net Periodic Pension Cost						
Service cost benefit earned	$ 9	$ 9	$ 9	$ 12	$ 16	$ 15
Interest cost on projected benefit obligation	27	27	26	39	38	35
Expected return on plan assets	(33)	(36)	(36)	(42)	(46)	(42)
Amortization of prior service cost			1	1	1	1
Amortization of loss	5	3	6	2	5	7
Net periodic pension cost	8	3	6	12	14	16
Other Changes in Plan Assets and Benefit Obligations Recognized in Other Comprehensive Income						
Current year actuarial loss (gain)	(31)	169	(11)	51	77	30
Amortization of actuarial loss	(5)	(3)	(6)	(2)	(5)	(7)
Amortization of prior service credit			(1)	(1)	(1)	(1)
Current year prior service cost				6	4	
Effects of eliminating early measurement date						(27)
Foreign currency translation effect				17	(38)	18
Total decrease (increase) in other comprehensive income	(36)	166	(18)	71	37	13
Total recognized in net periodic pension cost and other comprehensive income	$ (28)	$ 169	$ (12)	$ 83	$ 51	$ 29

At December 31, 2009, approximately $8 million and $16 million of actuarial losses will be amortized from AOCI on the Consolidated Balance Sheets into net periodic benefit cost in 2010 for the U.S. and Canadian pension plans, respectively. At December 31, 2009, approximately $2 million of prior service costs were included in AOCI that will be recognized in net periodic costs in 2010 for the Canadian plans.

Qualified Pension Plans Assumptions Used for Pension Benefits Accounting

	U.S. 2009	2008	2007	Canada 2009	2008	2007
Benefit Obligations						
Discount rate	5.28%	5.91%	6.00%	5.87%	6.46%	5.25%
Salary increase	4.73	5.77	5.71	3.50	3.50	3.50
Net Periodic Benefit Cost						
Discount rate	5.91	6.00	5.75	6.46	5.25	5.00
Salary increase	5.77	5.71	5.71	3.50	3.50	3.50
Expected long-term rate of return on plan assets	7.25	7.50	8.00	7.00	7.25	7.25

The discount rate used to determine the pension obligation is the rate at which the pension obligations could be effectively settled. The discount rate for our U.S. plan is developed from yields on available high-quality bonds and reflects the plan s expected cash flows. For our Canadian plan, the discount rate is the yield on Canadian corporate AA bonds with cash flows that match the timing and amount of the expected benefit payments under the plan.

Qualified Pension Plan Assets

Asset Category	U.S. Target Allocation	U.S. December 31, 2009	U.S. December 31, 2008	Canada Target Allocation	Canada December 31, 2009	Canada December 31, 2008
U.S. equity securities	44%	46%	41%	15%	15%	14%
Canadian equity securities				30	31	24
Other equity securities	20	20	16	15	15	14
Debt securities	36	34	43	40	39	48
Total	100%	100%	100%	100%	100%	100%

Pension plan assets are maintained in master trusts in both the U.S. and Canada. 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. 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. We regularly review our actual asset allocation and periodically rebalance our investments to the targeted allocation when considered appropriate.

The following table summarizes the fair values of the pension plan assets recorded at each hierarchy level at December 31, 2009:

	U.S. Total	U.S. Level 1	U.S. Level 2	U.S. Level 3	Canada Total	Canada Level 1	Canada Level 2	Canada Level 3
				(in millions)				
Cash and cash equivalents	$	$	$	$	$ 3	$ 3	$	$
Fixed income securities	147	147			236		236	
Equity securities	256	256			363		363	
Other	2		2		3			3
Total	$ 405	$ 403	$ 2	$	$ 605	$ 3	$ 599	$ 3

See Note 16 for a description of valuation techniques used to determine fair value.

The long-term rates of return of 7.25% and 7.00% as of December 31, 2009 for U.S. and Canadian assets, respectively, were 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. and Canadian plans respective targeted asset mix.

Qualified Pension Plans Expected Benefit Payments

The following benefit payments, which reflect expected future service, are expected to be paid over the next five years and thereafter:

	U.S.	Canada
	(in millions)	
2010	$ 39	$ 37
2011	40	39
2012	43	40
2013	42	42
2014	42	45
2015 2019	247	265

Non-Qualified Pension Plans

We maintain a non-qualified, non-contributory defined benefit retirement plan which covers certain U.S. executives. We also maintain a non-qualified, non-contributory defined benefit plan for our Canadian employees. The non-qualified plans have no plan assets.

Non-Qualified Pension Plans Change in Projected Benefit Obligation and Fair Value of Plan Assets

	U.S.		Canada	
	2009	2008	2009	2008
		(in millions)		
Change in Projected Benefit Obligation				
Projected benefit obligation, January 1	$ 20	$ 19	$ 72	$ 99
Service cost	1		1	1
Interest cost	1	1	5	5
Actuarial loss (gain)	1	2	12	(5)
Benefits paid	(1)	(2)	(5)	(12)
Foreign currency translation effect			12	(16)
Settlements	(3)			
Projected benefit obligation, December 31	19	20	97	72
Change in Fair Value of Plan Assets				
Plan assets, January 1				
Benefits paid	(1)	(2)	(5)	(5)
Employer contributions	4	2	5	5
Settlements	(3)			
Fair value of plan assets, December 31				
Amount recognized, December 31(a)	$ (19)	$ (20)	$ (97)	$ (72)

(a) Amounts are reflected in Deferred Credits and Other Liabilities Regulatory and Other within the Consolidated Balance Sheets.
During 2009, we paid lump sum amounts (settlements) which fully released plan obligations of approximately $3 million.

The accumulated benefit obligation of the U.S. plan was $16 million and $18 million at December 31, 2009 and 2008, respectively, and $93 million and $66 million at December 31, 2009 and 2008, respectively, for the Canadian plans.

Non-Qualified Pension Plans Amounts Recognized in Accumulated Other Comprehensive Income

The amounts recognized in AOCI for the U.S. plan were $2 million at December 31, 2009 and $1 million at December 31, 2008. Net actuarial losses for the Canadian non-qualified pension plans totaling $21 million at December 31, 2009 and $9 million at December 31, 2008 were recognized in AOCI.

At December 31, 2009, $1 million of unrecognized losses was included in AOCI that will be recognized in net periodic non-qualified pension costs in 2010 for the U.S. and Canadian plans.

Non-Qualified Pension Plans Components of Net Periodic Pension Costs

The following tables show the components of the pre-tax net periodic pension costs for our U.S. and Canadian non-qualified retirement plans:

	U.S.			Canada		
	2009	2008	2007	2009	2008	2007
	(in millions)					
Net Periodic Pension Cost						
Service cost benefit earned	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1
Interest cost on projected benefit obligation	1	1	1	5	5	5
Amortization of loss					1	1
Net periodic pension cost	2	2	2	6	7	7
Other Changes in Plan Assets and Benefits Obligations Recognized in Other Comprehensive Income						
Current year actuarial loss (gain)	1	1		12	(12)	(3)
Amortization of actuarial loss					(1)	(1)
Effects of eliminating early measurement date						(1)
Foreign currency translation effect					(2)	4
Total decrease (increase) in other comprehensive income	1	1		12	(15)	(1)
Total recognized in net periodic pension cost and other comprehensive income	$ 3	$ 3	$ 2	$ 18	$ (8)	$ 6

The lump sum payments associated with the settlements previously discussed did not have a significant effect on net period pension cost.

Non-Qualified Pension Plans Assumptions Used for Pension Benefits Accounting

	U.S.			Canada		
	2009	2008	2007	2009	2008	2007
Benefit Obligations						
Discount rate	5.28%	5.91%	6.00%	5.87%	6.46%	5.25%
Salary increase	4.45	4.77	5.10	3.50	3.50	3.50
Net Periodic Benefit Cost						
Discount rate	5.91	6.00	5.75	6.46	5.25	5.00
Salary increase	4.77	5.08	5.10	3.50	3.50	3.50

The discount rate used to determine the pension obligation is the rate at which the pension obligations could be effectively settled. The discount rate for our U.S. plan is developed from yields on available high-quality bonds and reflects the plan s expected cash flows. For our Canadian plan, the discount rate is the yield on Canadian corporate AA 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, are expected to be paid over the next five years and thereafter:

	U.S.	Canada
	(in millions)	
2010	$ 1	$ 6
2011	1	6
2012	1	6
2013	2	6
2014	2	6
2015 2019	9	24

Contributions for the non-qualified pension plans are equal to that of benefit payments, therefore, we expect to contribute $1 million to the U.S. plan and $6 million to the Canadian plan in 2010.

Other Post-Retirement Benefit Plans

U.S. Other Post-Retirement Benefits. We 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 us 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 1993 net unrecognized transition obligation from the adoption of a new accounting standard is being amortized over approximately 20 years, with four 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. We determine the market-related value of the plan assets using a calculated value that recognizes changes in fair value of the plan assets over five years for the U.S. plans.

Canadian Other Post-Retirement Benefits. We provide health care and life insurance benefits for retired employees on a non-contributory basis for our 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 previous defined benefit program. The Canadian plans are not funded.

Other Post-Retirement Benefit Plans Change in Projected Benefit Obligation and Fair Value of Plan Assets

	U.S. 2009	U.S. 2008	Canada 2009	Canada 2008
	(in millions)			
Change in Benefit Obligation				
Accumulated post-retirement benefit obligation, January 1	$ 241	$ 248	$ 80	$ 108
Service cost	1	1	2	3
Interest cost	14	14	6	5
Plan participants contribution	3	3		
Actuarial loss (gain)	(24)	(4)	11	(13)
Medicare subsidy receivable	3	3		
Benefits paid	(22)	(23)	(4)	(4)
Plan amendments	(3)			
Foreign currency translation effect			14	(19)
Accumulated post-retirement benefit obligation, December 31	213	242	109	80
Change in Fair Value of Plan Assets				
Plan assets, January 1	68	86		
Actual return (loss) on plan assets	8	(13)		
Benefits paid	(22)	(23)	(4)	(4)
Employer contributions	18	15	4	4
Plan participants contributions	3	3		
Plan assets, December 31	75	68		
Amount recognized, December 31(a)	$ (138)	$ (174)	$ (109)	$ (80)

(a) Recognized in Deferred Credits and Other Liabilities Regulatory and Other on the Consolidated Balance Sheets.

Other Post-Retirement Benefit Plan Amendments

In 2009, U.S. plan revisions were made which included increases to prescription drug payments and joining a group purchasing arrangement, which resulted in a $3 million decrease in benefit obligations.

Other Post-Retirement Benefit Plans Amounts Recognized in Accumulated Other Comprehensive Income

	U.S. December 31, 2009	U.S. December 31, 2008	Canada December 31, 2009	Canada December 31, 2008
	(in millions)			
Prior service costs (credits)	$	$	$ (8)	$ (9)
Net actuarial loss (gain)	22	51	9	(1)
Transition obligation	12	20		
Net decrease (increase) in AOCI	$ 34	$ 71	$ 1	$ (10)

At December 31, 2009, approximately $5 million of transition obligations and $1 million of actuarial losses were included in AOCI in the Consolidated Balance Sheets that will be recognized in net periodic costs in 2010 for the U.S. plan. At December 31, 2009, approximately $1 million of prior service credits were included in AOCI that will be recognized in net periodic costs in 2010 for the Canadian plans.

	U.S. 2009	U.S. 2008	U.S. 2007	Canada 2009	Canada 2008	Canada 2007
	(in millions)					
Other Post-Retirement Benefit Plans Components of Net Periodic Benefit Cost						
Service cost benefit earned	$ 1	$ 1	$ 1	$ 2	$ 3	$ 3
Interest cost on accumulated post-retirement benefit obligation	13	14	15	6	5	5
Expected return on plan assets	(5)	(5)	(6)			
Amortization of net transition liability	5	5	4			
Amortization of prior service credit			(2)	(1)		(1)
Amortization of loss	2	2	6			
Net periodic other post-retirement benefit cost	16	17	18	7	8	7
Other Changes in Plan Assets and Benefit Obligations Recognized in Other Comprehensive Income						
Current year actuarial loss (gain)	(27)	14	(26)	11	(13)	(2)
Amortization of actuarial loss	(2)	(2)	(4)			(1)
Current year prior service credit	(3)					
Amortization of prior service credit			2	1		1
Amortization of transition asset/obligation	(5)	(5)	(5)			
Foreign currency translation effect				(1)	1	1
Total decrease (increase) in other comprehensive income	(37)	7	(33)	11	(12)	(1)
Total recognized in net periodic benefit cost and other comprehensive income	$ (21)	$ 24	$ (15)	$ 18	$ (4)	$ 6

Other Post-Retirement Benefits Plans Assumptions Used

	U.S. 2009	U.S. 2008	U.S. 2007	Canada 2009	Canada 2008	Canada 2007
Benefit Obligations						
Discount rate for post-retirement life plans	5.51%	6.01%	6.00%	5.95%	6.57%	5.25%
Discount rate for post-retirement medical plans	5.30	5.95	6.00	5.95	6.57	5.25
Salary increase	4.73	5.71	5.70	3.50	3.50	3.50
Net Periodic Benefit Cost						
Discount rate for post-retirement life plans	6.01	6.00	5.75	6.57	5.25	5.00
Discount rate for post-retirement medical plans	5.95	6.00	5.75	6.57	5.25	5.00
Salary increase	5.77	5.71	5.70	3.50	3.50	3.50
Expected return on plan assets for post-retirement life plans	7.25	7.25	6.90	n/a	n/a	n/a
Expected return on plan assets for post-retirement medical plans	6.17	6.29	6.65	n/a	n/a	n/a

n/a indicates not applicable.

The discount rate used to determine the post-retirement obligation is the rate at which the pension obligations could be effectively settled. The discount rate for our U.S. plan is developed from yields on available high-quality bonds and reflects the plan s expected cash flows. For our Canadian plan, the discount rate is the yield on Canadian corporate AA 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. and Canada 2009	2008
Health care cost trend rate assumed for next year	8.00%	8.00%
Rate to which the cost trend is assumed to decline	5.00%	5.00%
Year that the rate reaches the ultimate trend rate	2016	2015

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 obligations	9	(9)	8	(7)

Other Post-Retirement Plan Assets

	U.S. December 31,	
Asset Category	**2009**	**2008**
Equity securities	49%	35%
Debt securities	45	49
Other assets	6	16
Total	100%	100%

A portion of our other post-retirement plan assets are maintained within the two master trusts discussed under pension plans above. We also invest other post-retirement plan 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.

The following table summarizes the fair values of the other post-retirement plan assets recorded at each hierarchy level at December 31, 2009:

	U.S.							
	VEBA I and VEBA II Trusts				Master Trust			
	Total	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3
	(in millions)							
Cash and cash equivalents	$ 5	$ 5	$	$	$	$	$	$
Fixed income securities	23		23		11	11		
Equity securities	17		17		19	19		
Total	$ 45	$ 5	$ 40	$	$ 30	$ 30	$	$

See Note 16 for a description of valuation techniques used to determine fair value.

Other Post-Retirement Plans Benefit Payments and Receipts

We expect to make future benefit payments, which reflect expected future service, as appropriate. As our plans provide benefits that are actuarially equivalent to the benefits received by Medicare recipients, we expect 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.	Benefit Payments Canada	Medicare Part D Subsidy Receipts U.S.
	(in millions)		
2010	$ 21	$ 4	$ 2
2011	21	5	2
2012	21	5	2
2013	21	5	2
2014	21	5	2
2015 2019	95	26	8

We anticipate making contributions of $13 million for the U.S. plans and $4 million for the Canadian plans in 2010.

Retirement Savings Plan

In 2007, we established an employee savings plan that covered substantially all U.S. employees. Most employees participate in a matching contribution formula where we provide a matching contribution generally equal to 100% of before-tax employee contributions, of up to 6% of eligible pay per pay period. We expensed pre-tax employer matching contributions of $11 million in 2009, $10 million in 2008 and $9 million in 2007.

24. Consolidating Financial Information

Spectra Energy Corp has 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, a wholly owned, consolidated subsidiary. In accordance with Securities and Exchange Commission (SEC) rules, the following condensed consolidating financial information is presented. The information shown for us 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 our accompanying Consolidated Financial Statements and notes thereto.

Spectra Energy Corp

Condensed Consolidating Statement of Operations

Year Ended December 31, 2009

(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Total operating revenues	$	$	$ 4,552	$	$ 4,552
Total operating expenses	10	7	3,071		3,088
Gains on sales of other assets and other, net			11		11
Operating income (loss)	(10)	(7)	1,492		1,475
Equity in earnings of unconsolidated affiliates			369		369
Equity in earnings of subsidiaries	856	1,238		(2,094)	
Other income and expenses, net	1	23	13		37
Interest expense	1	207	402		610
Earnings from continuing operations before income taxes	846	1,047	1,472	(2,094)	1,271
Income tax expense (benefit) from continuing operations	(2)	191	164		353
Income from continuing operations	848	856	1,308	(2,094)	918
Income from discontinued operations, net of tax			5		5
Net income	848	856	1,313	(2,094)	923
Net income noncontrolling interests			75		75
Net income controlling interests	$ 848	$ 856	$ 1,238	$ (2,094)	$ 848

Spectra Energy Corp

Condensed Consolidating Statement of Operations

Year Ended December 31, 2008

(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Total operating revenues	$	$	$ 5,074	$	$ 5,074
Total operating expenses	7		3,629		3,636
Gains on sales of other assets and other, net			42		42
Operating income (loss)	(7)		1,487		1,480
Equity in earnings of unconsolidated affiliates			778		778
Equity in earnings of subsidiaries	1,123	1,648		(2,771)	
Other income and expenses, net	1	23	42		66
Interest expense		249	387		636

Earnings from continuing operations before income taxes	1,117	1,422	1,920	(2,771)	1,688
Income tax expense (benefit) from continuing operations	(12)	299	209		496
Income from continuing operations	1,129	1,123	1,711	(2,771)	1,192
Income from discontinued operations, net of tax			2		2
Net income	1,129	1,123	1,713	(2,771)	1,194
Net income noncontrolling interests			65		65
Net income controlling interests	$ 1,129	$ 1,123	$ 1,648	$ (2,771)	$ 1,129

Spectra Energy Corp

Condensed Consolidating Statement of Operations

Year Ended December 31, 2007

(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Total operating revenues	$	$	$ 4,704	$	$ 4,704
Total operating expenses	46	6	3,239		3,291
Gains on sales of other assets and other, net			13		13
Operating income (loss)	(46)	(6)	1,478		1,426
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
Earnings from continuing operations before income taxes	943	1,216	1,708	(2,425)	1,442
Income tax expense (benefit) from continuing operations	(14)	230	224		440
Income from continuing operations	957	986	1,484	(2,425)	1,002
Income from discontinued operations, net of tax			25		25
Net income	957	986	1,509	(2,425)	1,027
Net income noncontrolling interests			70		70
Net income controlling interests	$ 957	$ 986	$ 1,439	$ (2,425)	$ 957

Spectra Energy Corp

Condensed Consolidating Balance Sheet

December 31, 2009

(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Cash and cash equivalents	$	$	$ 196	$	$ 196
Receivables (payables) consolidated subsidiaries	(28)	248	(220)		
Receivables (payables) other	(4)	2	780		778
Other current assets	6	6	443		455
Total current assets	(26)	256	1,199		1,429
Investments in and loans to unconsolidated affiliates		74	1,927		2,001
Investments in consolidated subsidiaries	9,319	12,538		(21,857)	
Advances receivable (payable) consolidated subsidiaries	(2,063)	2,440	(30)	(347)	
Goodwill			3,948		3,948
Other assets	38	30	339		407
Property, plant and equipment, net			15,347		15,347
Regulatory assets and deferred debits	1	15	931		947
Total Assets	$ 7,269	$ 15,353	$ 23,661	$ (22,204)	$ 24,079
Accounts payable (receivable) consolidated subsidiaries	$	$ 41	$ (41)	$	$
Accounts payable other	1	93	239		333
Short-term borrowings and commercial paper		388	121	(347)	162
Accrued taxes payable (receivable)	(93)	54	178		139
Current maturities of long-term debt		9	800		809
Other current liabilities	64	64	924		1,052
Total current liabilities	(28)	649	2,221	(347)	2,495
Long-term debt		3,282	5,665		8,947
Deferred credits and other liabilities	172	2,103	2,472		4,747
Preferred stock of subsidiaries			225		225
Equity					
Controlling interests	7,125	9,319	12,538	(21,857)	7,125
Noncontrolling interests			540		540
Total equity	7,125	9,319	13,078	(21,857)	7,665
Total Liabilities and Equity	$ 7,269	$ 15,353	$ 23,661	$ (22,204)	$ 24,079

Spectra Energy Corp

Condensed Consolidating Balance Sheet

December 31, 2008

(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Cash and cash equivalents	$	$ 60	$ 154	$	$ 214
Receivables (payables) consolidated subsidiaries	(25)	250	(220)	(5)	
Receivables other	1	11	783		795
Other current assets	39	35	367		441
Total current assets	15	356	1,084	(5)	1,450
Investments in and loans to unconsolidated affiliates		368	1,784		2,152
Investments in consolidated subsidiaries	7,375	10,482		(17,857)	
Advances receivable (payable) consolidated subsidiaries	(1,937)	3,298	(992)	(369)	
Goodwill			3,381		3,381
Other assets	40	66	311		417
Property, plant and equipment, net			13,639		13,639
Regulatory assets and deferred debits	1	15	869		885
Total Assets	$ 5,494	$ 14,585	$ 20,076	$ (18,231)	$ 21,924
Accounts payable (receivable) consolidated subsidiaries	$ 5	$ 41	$ (41)	$ (5)	$
Accounts payable other	1	124	160		285
Short-term borrowings and commercial paper		1,137	168	(369)	936
Accrued taxes payable (receivable)	(297)	266	136		105
Current maturities of long-term debt		648	173		821
Other current liabilities	19	106	772		897
Total current liabilities	(272)	2,322	1,368	(374)	3,044
Long-term debt		3,009	5,281		8,290
Deferred credits and other liabilities	226	1,879	2,250		4,355
Preferred stock of subsidiaries			225		225
Equity					
Controlling interests	5,540	7,375	10,482	(17,857)	5,540
Noncontrolling interests			470		470
Total equity	5,540	7,375	10,952	(17,857)	6,010
Total Liabilities and Equity	$ 5,494	$ 14,585	$ 20,076	$ (18,231)	$ 21,924

Spectra Energy Corp

Condensed Consolidating Statements of Cash Flows

Year Ended December 31, 2009

(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES					
Net income	$ 848	$ 856	$ 1,313	$ (2,094)	$ 923
Adjustments to reconcile net income to net cash provided by operating activities:					
Depreciation and amortization			598		598
Equity in earnings of unconsolidated affiliates			(369)		(369)
Equity in earnings of subsidiaries	(856)	(1,238)		2,094	
Distributions received from unconsolidated affiliates			195		195
Other	31	137	245		413
Net cash provided by (used in) operating activities	23	(245)	1,982		1,760
CASH FLOWS FROM INVESTING ACTIVITIES					
Capital expenditures			(980)		(980)
Investments in and loans to unconsolidated affiliates		(29)	(32)		(61)
Acquisition of NOARK			(295)		(295)
Proceeds from sales and maturities of available-for-sale securities			32		32
Distributions received from unconsolidated affiliates			164		164
Receipt from affiliate repayment of loan		186			186
Other			(46)		(46)
Net cash provided by (used in) investing activities		157	(1,157)		(1,000)
CASH FLOWS FROM FINANCING ACTIVITIES					
Proceeds from the issuance of long-term debt		300	3,827		4,127
Payments for the redemption of long-term debt		(648)	(3,375)		(4,023)
Net decrease in short-term borrowings and commercial paper		(726)	(48)		(774)
Distributions to noncontrolling interests			(174)		(174)
Contributions from noncontrolling interests			2		2
Proceeds from the issuance of Spectra Energy common stock	448				448
Proceeds from the issuance of Spectra Energy Partners, LP common units			208		208
Dividends paid on common stock	(631)	(12)		12	(631)
Distributions and advances from (to) parent	136	1,116	(1,240)	(12)	
Other	24	(2)	(8)		14
Net cash provided by (used in) financing activities	(23)	28	(808)		(803)
Effect of exchange rate changes on cash			25		25
Net increase (decrease) in cash and cash equivalents		(60)	42		(18)
Cash and cash equivalents at beginning of period		60	154		214
Cash and cash equivalents at end of period	$	$	$ 196	$	$ 196

Spectra Energy Corp

Condensed Consolidating Statements of Cash Flows

Year Ended December 31, 2008

(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES					
Net income	$ 1,129	$ 1,123	$ 1,713	$ (2,771)	$ 1,194
Adjustments to reconcile net income to net cash provided by operating activities:					
Depreciation and amortization			581		581
Equity in earnings of unconsolidated affiliates			(778)		(778)
Equity in earnings of subsidiaries	(1,123)	(1,648)		2,771	
Distributions received from unconsolidated affiliates			777		777
Other	(63)	112	(18)		31
Net cash provided by (used in) operating activities	(57)	(413)	2,275		1,805
CASH FLOWS FROM INVESTING ACTIVITIES					
Capital expenditures			(1,502)		(1,502)
Investments in and loans to unconsolidated affiliates		(219)	(309)		(528)
Acquisition of Spectra Energy Income Fund			(274)		(274)
Purchases of available-for-sale securities			(1,132)		(1,132)
Proceeds from sales and maturities of available-for-sale securities			1,256		1,256
Net proceeds from the sales of other assets			105		105
Distributions received from unconsolidated affiliates			218		218
Other			(31)		(31)
Net cash used in investing activities		(219)	(1,669)		(1,888)
CASH FLOWS FROM FINANCING ACTIVITIES					
Proceeds from the issuance of long-term debt		1,000	2,557		3,557
Payments for the redemption of long-term debt			(2,400)		(2,400)
Net increase (decrease) in short-term borrowings and commercial paper		290	(41)		249
Distributions to noncontrolling interests			(70)		(70)
Contributions from noncontrolling interests			115		115
Repurchases of Spectra Energy common stock	(600)				(600)
Dividends paid on common stock	(598)	(13)		13	(598)
Distributions and advances from (to) parent	1,241	(585)	(643)	(13)	
Other	14		(53)		(39)
Net cash provided by (used in) financing activities	57	692	(535)		214
Effect of exchange rate changes on cash			(11)		(11)
Net increase in cash and cash equivalents		60	60		120
Cash and cash equivalents at beginning of period			94		94
Cash and cash equivalents at end of period	$	$ 60	$ 154	$	$ 214

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	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES					
Net income	$ 957	$ 986	$ 1,509	$ (2,425)	$ 1,027
Adjustments to reconcile net income to net cash provided by operating activities:					
Depreciation and amortization			534		534
Equity in earnings of unconsolidated affiliates			(596)		(596)
Equity in earnings of subsidiaries	(986)	(1,439)		2,425	
Distributions received from unconsolidated affiliates			569		569
Other	(179)	322	(210)		(67)
Net cash provided by (used in) operating activities	(208)	(131)	1,806		1,467
CASH FLOWS FROM INVESTING ACTIVITIES					
Capital expenditures		(2)	(1,200)		(1,202)
Investments in and loans to unconsolidated affiliates		(152)	(133)		(285)
Acquisitions, net of cash acquired			(14)		(14)
Purchases of available-for-sale securities			(1,550)		(1,550)
Proceeds from sales and maturities of available-for-sale securities			1,405		1,405
Net proceeds from the sales of other assets			15		15
Distributions received from unconsolidated affiliates			87		87
Net cash used in investing activities		(154)	(1,390)		(1,544)
CASH FLOWS FROM FINANCING ACTIVITIES					
Proceeds from the issuance of long-term debt		369	783	(369)	783
Payments for the redemption of long-term debt			(981)		(981)
Net increase in short-term borrowings and commercial paper		129	237		366
Distributions to noncontrolling interests			(57)		(57)
Contributions from noncontrolling interests			9		9
Proceeds from the issuance of Spectra Energy Partners, LP common units			230		230
Dividends paid on common stock	(558)	(5)		5	(558)
Distributions and advances from (to) parent	766	(164)	(966)	364	
Other			17		17
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

25. Quarterly Financial Data (Unaudited)

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
		(in millions, except per share amounts)			
2009					
Operating revenues	$ 1,384	$ 937	$ 933	$ 1,298	$ 4,552
Operating income	425	317	353	380	1,475
Net income	315	157	212	239	923
Net income controlling interests	298	140	191	219	848
Earnings per share(a)					
Basic	0.47	0.22	0.30	0.34	1.32
Diluted	0.47	0.22	0.30	0.34	1.32
2008					
Operating revenues	1,600	1,133	1,080	1,261	5,074
Operating income	493	343	340	304	1,480
Net income	386	309	312	187	1,194
Net income controlling interests	367	295	296	171	1,129
Earnings per share(a)					
Basic	0.58	0.47	0.48	0.28	1.82
Diluted	0.58	0.47	0.48	0.28	1.81

(a) Quarterly earnings-per-share amounts are stand-alone calculations and may not be additive to full-year amounts due to rounding.

Unusual or Infrequent Items

During the first quarter of 2009, we recorded in Equity in Earnings of Unconsolidated Affiliates in the Consolidated Statement of Operations a $135 million gain ($85 million after tax) associated with the reclassification by DCP Midstream of certain deferred gains on sales of common units in its master limited partnership. See Note 10 for further discussion.

During the fourth quarter of 2008, we recorded a $44 million charge ($30 million after tax) representing our share of impaired assets associated with the Islander East pipeline project, of which $12 million is included in Operating, Maintenance and Other expense and $32 million is included in Equity in Earnings of Unconsolidated Affiliates. See Note 10 for further discussion.

During the second quarter of 2008, we recorded a $31 million gain ($21 million after tax) related to consideration received for a customer bankruptcy settlement which is included in Gains on Sales of Other Assets and Other, Net. See Note 9 for further discussion.

26. Subsequent Events

We have evaluated significant events and transactions that occurred from January 1, 2010 through February 25, 2010 and have determined that there were no events or transactions other than those disclosed in this report, if any, that would require recognition or disclosure in our Consolidated Financial Statements for the year ended December 31, 2009.

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, 2009:					
Allowance for doubtful accounts	$ 12	$ 4	$ 2	$ 4	$ 14
Other(b)	175	60	12	108	139
	$ 187	$ 64	$ 14	$ 112	$ 153
December 31, 2008:					
Allowance for doubtful accounts	$ 22	$ 7	$	$ 17	$ 12
Other(b)	204	34	5	68	175
	$ 226	$ 41	$ 5	$ 85	$ 187
December 31, 2007:					
Allowance for doubtful accounts	$ 13	$ 17	$	$ 8	$ 22
Other(b)	236	20	98	150	204
	$ 249	$ 37	$ 98	$ 158	$ 226

(a) Principally cash payments and reserve reversals.

(b) Principally income tax reserves, 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 on 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 us in the reports we file or submit under the Securities Exchange Act of 1934 (Exchange Act) is recorded, processed, summarized, and reported within the time periods specified by the SEC s 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 us in the reports we file or submit 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, we have evaluated the effectiveness of our 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, 2009, and, based upon this evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that these controls and procedures are effective.

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, we have 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, 2009 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 our Proxy Statement relating to our 2010 annual meeting of shareholders.

Item 11. Executive Compensation.

Information in response to this item is incorporated by reference from our Proxy Statement relating to our 2010 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 our Proxy Statement relating to our 2010 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 our Proxy Statement relating to our 2010 annual meeting of shareholders.

Item 14. Principal Accounting Fees and Services.

Information in response to this item is incorporated by reference from our Proxy Statement relating to our 2010 annual meeting of shareholders.

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

Consolidated Balance Sheets

Consolidated Statements of Cash Flows

Consolidated Statements of Equity and Comprehensive Income

Notes to Consolidated Financial Statements

Consolidated Financial Statement Schedule II Valuation and Qualifying Accounts and Reserves

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.

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 25, 2010

SPECTRA ENERGY CORP

By: /s/ Gregory L. Ebel
Gregory L. Ebel

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) Gregory L. Ebel*
President and Chief Executive Officer (Principal Executive Officer and Director)

(ii) J. Patrick Reddy*
Chief Financial Officer (Principal Financial Officer)

(iii) Sabra L. Harrington*
Vice President and Controller (Principal Accounting Officer)

(iv) William T. Esrey*
Chairman of the Board of Directors

Austin A. Adams*

Director

Paul M. Anderson*

Director

Pamela L. Carter*

Director

Tony Comper*

Director

Peter B. Hamilton*

Director

Dennis R. Hendrix*

Director

Michael McShane*

Director

Michael E.J. Phelps *

Director

Date: February 25, 2010

J. Patrick Reddy, 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/ J. Patrick Reddy
J. Patrick Reddy

Attorney-In-Fact

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 No. 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).
3.1.1	Certificate of Amendment to the 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 May 13, 2009).
3.2	Amended and Restated By-laws of Spectra Energy Corp (Amended and Restated as of May 8, 2009) (filed as Exhibit No. 3.2 to Form 8-K of Spectra Energy Corp on May 13, 2009).
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).
4.2	First Supplemental Indenture, dated July 20, 1998, between Duke Capital Corporation and The Chase Manhattan Bank (filed as Exhibit No. 4.2 to Form 10-K of Duke Capital Corporation on March 16, 2004).
4.3	Second Supplemental Indenture, dated September 28, 1999, between Duke Capital Corporation and The Chase Manhattan Bank (filed as Exhibit No. 4.3 to Form 10-K of Duke Capital Corporation on March 16, 2004).
4.4	Fifth Supplemental Indenture, dated February 15, 2002, between Duke Capital Corporation and JPMorgan Chase Bank (filed as Exhibit No. 4.6 to Form 10-K of Duke Capital Corporation on March 16, 2004).

Exhibit No.	Exhibit Description
4.5	Ninth Supplemental Indenture, dated February 20, 2004, between Duke Capital Corporation and JPMorgan Chase Bank (filed as Exhibit No. 4.10 to Form 10-K of Duke Capital Corporation on March 16, 2004).
4.6	Eleventh Supplemental Indenture, dated August 19, 2004, between Duke Capital LLC and JPMorgan Chase Bank (filed as Exhibit No. 4.6 to Form S-3 of Spectra Energy Corp and Spectra Energy Capital, LLC on March 26, 2008, File No. 333-141982).
4.7	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).
4.8	Thirteenth Supplemental Indenture, dated as of April 10, 2008, between Spectra Energy Capital, LLC, Spectra Energy Corp and The Bank of New York Trust Company, N.A. (filed as Exhibit No. 4.1 to Form 8-K on April 10, 2008).
4.9	Fourteenth Supplemental Indenture, dated as of September 8, 2008, between Spectra Energy Capital, LLC, Spectra Energy Corp and The Bank of New York Mellon Trust Company, N.A. (filed as Exhibit No. 4.1 to Form 8-K on September 9, 2008).
4.10	Indenture, dated May 14, 2009, between Maritimes & Northeast Pipeline, LLC and Deutsch Bank Trust Company Americas (filed as Exhibit No. 4.1 to Form 10-Q of Spectra Energy Corp for the quarter ended June 30, 2009).
4.11	First Supplemental Indenture, dated May 14, 2009, between Maritimes & Northeast Pipeline, LLC and Deutsch Bank Trust Company Americas (filed as Exhibit No. 4.2 to Form 10-Q of Spectra Energy Corp for the quarter ended June 30, 2009).
4.12	Fifteenth Supplemental Indenture, dated as of August 28, 2009, between Spectra Capital, Spectra Energy and The Bank of New York Mellon Trust Company, N.A. (filed as Exhibit No. 4.1 to Form 8-K on August 28, 2009).
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 10-Q of Spectra Energy Corp for the quarter ended June 30, 2009).
10.2	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 10-Q of Spectra Energy Corp for the quarter ended June 30, 2009).
10.2.1	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. 10.3.1 to Form 10-Q of Spectra Energy Corp for the quarter ended June 30, 2009).
10.3	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. 10.4 to Form 10-Q of Spectra Energy Corp for the quarter ended June 30, 2009).
10.4	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).
10.5	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-Q of Spectra Energy Corp for the quarter ended June 30, 2009).
10.6	Limited Liability Company Agreement of Gulfstream Management & Operating Services, LLC, dated as of February 1, 2001, between Duke Energy Gas Transmission Corporation and Williams Gas Pipeline Company (filed as Exhibit No. 10.18 to Form 10-K of Duke Energy Corporation for the year ended December 31, 2002).

Exhibit No.	Exhibit Description
10.7	Loan Agreement, dated as of February 25, 2005, between DCP Midstream, LLC and Duke Capital LLC (filed as Exhibit No. 10.6 to Form 10-Q of Spectra Energy Corp for the quarter ended June 30, 2009).
+10.8	Spectra Energy Corp Directors Savings Plan (filed as Exhibit No. 10.1 to Form 8-K of Spectra Energy Corp on December 22, 2006).
*+10.8.1	Third Amendment, dated December 8, 2009, to Spectra Energy Corp Directors Savings Plan.
+10.9	Spectra Energy Corp Executive Savings Plan (filed as Exhibit No. 10.2 to Form 8-K of Spectra Energy Corp on December 22, 2006).
*+10.9.1	Third Amendment, dated December 8, 2009, to Spectra Energy Corp Executive Savings Plan.
+10.10	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).
*+10.10.1	Third Amendment, dated December 8, 2009, to Spectra Energy Corp Executive Cash Balance Plan.
+10.11	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).
+10.12	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).
+10.13	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).
+10.14	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).
10.15	$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).
10.15.1	Amendment No. 1, dated April 8, 2008, among Spectra Energy Corp, Spectra Energy Capital, LLC, JPMorgan Chase Bank, N.A., as Administrative Agent and the banks listed therein to the Credit Agreement dated May 21, 2007 (filed as Exhibit No. 10.2 to Form 10-Q of Spectra Energy Corp for the quarter ended March 31, 2008).
10.15.2	Amendment No. 2, dated September 28, 2009, among Spectra Energy Corp, Spectra Energy Capital, LLC, JPMorgan Chase Bank, N.A., as Administrative Agent and the banks listed therein to the Credit Agreement dated May 21, 2007 (filed as Exhibit No. 10.1 to Form 10-Q of Spectra Energy Corp for the quarter ended September 30, 2009).
10.16	Support Agreement among Spectra Energy Midstream Holdco Management Partnership, Spectra Energy Income Fund and Spectra Energy Commercial Trust, dated March 4, 2008 (filed as Exhibit No. 10.1 to Form 10-Q of Spectra Energy Corp for the quarter ended March 31, 2008).
+10.17	Form of Phantom Stock Award Agreement pursuant to the Spectra Energy Corp 2007 Long-Term Incentive Plan (filed as Exhibit No. 10.1 to Form 10-Q of Spectra Energy Corp for the quarter ended June 30, 2008).
+10.18	Form of Performance Award Agreement pursuant to the Spectra Energy Corp 2007 Long-Term Incentive Plan (filed as Exhibit 10.2 to Form 10-Q of Spectra Energy Corp for the quarter ended June 30, 2008).
*+10.19	Form of Phantom Stock Award Agreement (2010) pursuant to the Spectra Energy Corp 2007 Long-Term Incentive Plan.

Exhibit No.	Exhibit Description
*+10.20	Form of Performance Award Agreement (2010) pursuant to the Spectra Energy Corp 2007 Long-Term Incentive Plan.
*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.
*24.1	Power of Attorney.
*31.1	Certification of the Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*31.2	Certification of the Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*32.1	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*32.2	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*101.INS	XBRL Instance Document.
*101.SCH	XBRL Taxonomy Extension Schema.
*101.CAL	XBRL Taxonomy Extension Calculation Linkbase.
*101.DEF	XBRL Taxonomy Extension Definition Linkbase.
*101.LAB	XBRL Taxonomy Extension Label Linkbase.
*101.PRE	XBRL Taxonomy Extension Presentation Linkbase.

+ Denotes management contract or compensatory plan or arrangement.
* Filed herewith.