Spectra Energy Corp.
Form 10-K
February 22, 2013
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UNITED STATES SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-K

x ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2012 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, 2012: $18,900,000,000

Number of shares of Common Stock, $0.001 par value, outstanding at January 31, 2013: 668,132,135

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the proxy statement for the 2013 Annual Meeting of Shareholders are incorporated by reference in Part III.

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SPECTRA ENERGY CORP

FORM 10-K FOR THE YEAR ENDED

DECEMBER 31, 2012

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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 represent management s intentions, plans, expectations, assumptions and beliefs about future events. 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 are subject to risks, uncertainties and other factors, many of which are outside our control and could cause actual results to differ materially from the results expressed or implied by those forward-looking statements. Factors used to develop these forward-looking statements and 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 and oil industries;

outcomes of litigation and regulatory investigations, proceedings or inquiries;

weather and other natural phenomena, including the economic, operational and other effects of hurricanes and storms;

the timing and extent of changes in commodity prices, interest rates and foreign currency exchange rates;

general economic conditions, including the risk of a prolonged economic slowdown or decline, or the risk of delay in a recovery, which can affect the long-term demand for natural gas and oil and related services;

potential effects arising from terrorist attacks and any consequential or other hostilities;

changes in environmental, safety and other laws and regulations;

the development of alternative energy resources;

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 related infrastructure projects and the effects of competition;

- the performance of natural gas and oil transmission and storage, distribution, and gathering and processing facilities;

- the extent of success in connecting natural gas and oil supplies to gathering, processing and transmission systems and in connecting to expanding gas and oil markets;

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

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

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

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

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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 over 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 currently operate 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), based in Denver, Colorado, one of the leading natural gas gatherers in the United States based on wellhead volumes, and one of the largest U.S. producers and marketers of natural gas liquids (NGLs). Our internet website is *http://www.spectraenergy.com*.

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Our natural gas pipeline systems consist of over 19,000 miles of transmission pipelines. Our proportional throughput for our pipelines totaled 4,189 trillion British thermal units (TBtu) in 2012, compared to 4,329 TBtu in 2011 and 4,248 TBtu in 2010. These amounts include throughput on 100%-owned U.S. and Canadian pipelines and our proportional share of throughput on pipelines that are not 100%-owned. Our storage facilities provide approximately 305 billion cubic feet (Bcf) of net storage capacity in the United States and Canada.

Businesses

We currently 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, 100%-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 primarily 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 14,600 miles of transmission pipelines with eight 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. (M&N LLC) and Maritimes & Northeast Pipeline Limited Partnership (collectively, Maritimes & Northeast Pipeline), Ozark Gas Transmission, L.L.C. (Ozark Gas Transmission), Big Sandy Pipeline, LLC (Big Sandy), 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. A majority of contracted transportation volumes are under long-term firm service agreements, where customers reserve capacity in the pipeline. Interruptible services, where customers can use capacity if it is available at the time of the request, are provided on a short-term or seasonal basis.

U.S. Transmission provides natural gas 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), Bobcat Gas Storage (Bobcat) 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.

U.S. Transmission s proportional throughput for its natural gas pipelines totaled 2,709 TBtu in 2012, compared to 2,770 TBtu in 2011 and 2,708 TBtu in 2010. This includes throughput on 100%-owned pipelines and our proportional share of throughput on pipelines that are not 100%-owned. Demand on the pipeline and storage systems is seasonal, with the highest throughput occurring during colder periods in the first and fourth calendar quarters, and storage injections occurring primarily during the summer periods. Actual throughput and storage injections/withdrawals do not have a significant impact on revenues or earnings.

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.

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We currently own a 61% equity interest in Spectra Energy Partners, LP (Spectra Energy Partners), a natural gas infrastructure master limited partnership, which owns 100% of East Tennessee, 100% of Saltville, 100% of Ozark Gas Gathering and Ozark Gas Transmission, 100% of Big Sandy, 50% of Market Hub, 49% of Gulfstream and 39% of M&N LLC. Spectra Energy directly owns the remaining 50% interest in Market Hub, a 1% interest in Gulfstream and a 39% interest in M&N LLC. Spectra Energy Partners is a publicly traded entity which trades on the New York Stock Exchange under the symbol SEP. See Part II. Item 8. Financial Statements and Supplementary Data, Note 2 of Notes to Consolidated Financial Statements for further discussion of Spectra Energy Partners.

Texas Eastern

The Texas Eastern natural 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 associated 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 pipeline. Texas Eastern has two storage facilities in Pennsylvania held through joint ventures and one 100%-owned and operated storage facility in Maryland. Texas Eastern s total working capacity in these three facilities is 74 Bcf. In addition, Texas Eastern s system is connected to Steckman Ridge, a 12 Bcf storage facility in Pennsylvania owned by our joint venture with New Jersey Resources (NJR), and three affiliated storage facilities in Texas and Louisiana, aggregating 65 Bcf, owned by Market Hub and Bobcat.

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New Jersey-New York Expansion. The New Jersey New York project is designed to extend our reach farther into New Jersey and into the New York City market for the first time in several decades. The project is expected to provide 800 million cubic-feet-per-day (MMcf/d) of new capacity and involves the construction of 16 miles of new 30-inch pipeline extending from Staten Island to Manhattan, replacement of five miles of pipeline with 42-inch pipe, three compressor station reversals and other upgrades. The capital cost of the project is expected to be approximately $1.2 billion. We received approval from the FERC in May 2012. Various parties filed requests for rehearing and stay of the May 2012 FERC order approving construction and operation of the project. The FERC issued an order on October 18, 2012 denying requests for rehearing, reconsideration, stay and late intervention, effectively exhausting the administrative remedies available to the parties. Three petitions for review of FERC s orders have been filed with the D.C. Circuit Court of Appeals. The petitions have been consolidated into a single docket but a procedural schedule has not been set by the court. Construction of the project is ongoing and we expect to place the project into service in the second half of 2013.

Algonquin

The Algonquin natural gas transmission system 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 1,125 miles of pipeline with associated compressor stations.

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East Tennessee

East Tennessee s natural gas transmission system crosses Texas Eastern s system at two locations in Tennessee and consists of two mainline systems totaling approximately 1,500 miles of pipeline in Tennessee, Georgia, North Carolina and Virginia, with associated 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 61% ownership interest in East Tennessee through our ownership of Spectra Energy Partners.

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Maritimes & Northeast Pipeline

Maritimes & Northeast Pipeline s natural gas transmission system is operated through Maritimes & Northeast Pipeline Limited Partnership (M&N LP), the Canadian portion of this system, and M&N LLC, the U.S. portion. Spectra Energy has a direct 78% ownership interest in M&N LP and affiliates of Exxon Mobil Corporation and Emera, Inc. have the remaining interests. Spectra Energy has an effective 63% ownership interest in M&N LLC. M&N LLC is directly owned 39% by Spectra Energy, 39% by Spectra Energy Partners and 22% by affiliates of Exxon Mobil Corporation and Emera, Inc. The Maritimes & Northeast Pipeline transmission system consists of approximately 890 miles of pipeline, with associated compressor stations, originating in Nova Scotia through New Brunswick, Maine, New Hampshire and Massachusetts, connecting to the Algonquin system in Beverly, Massachusetts.

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Ozark

We have an effective 61% ownership interest in Ozark Gas Transmission and Ozark Gas Gathering, which was acquired by Spectra Energy Partners in 2009. Ozark Gas Transmission consists of a 565-mile natural gas transmission system extending from southeastern Oklahoma through Arkansas to southeastern Missouri. Ozark Gas Gathering consists of a 365-mile natural gas gathering system, with associated compressor stations, that primarily serves Arkoma basin producers in eastern Oklahoma.

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Big Sandy

We have an effective 61% ownership interest in Big Sandy, which was acquired by Spectra Energy Partners in 2011. Big Sandy is a 70-mile natural gas transmission system, with associated compressor stations, located in eastern Kentucky. Big Sandy s interconnection with the Tennessee Gas Pipeline system links the Huron Shale and Appalachian Basin natural gas supplies to the mid-Atlantic and northeast markets.

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Gulfstream

We have an effective 31% investment in Gulfstream, a 745-mile interstate natural gas transmission system, with associated compressor stations, 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 is directly owned 1% by Spectra Energy, 49% 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.

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SESH

We have a 50% investment in SESH, a 290-mile natural gas transmission system, with associated compressor stations, owned and operated jointly by us and CenterPoint Energy, Inc. SESH, which began operations in 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 81% 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 51 Bcf. The Moss Bluff facility consists of four salt dome storage caverns located in southeast Texas, with access to five pipeline systems including the Texas Eastern system. The Egan facility consists of four salt dome storage caverns located in south central Louisiana, with access to eight 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% direct interest.

Saltville

We have an effective 61% 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, interconnecting 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.

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Bobcat

We have a 100% ownership interest in Bobcat, a 14 Bcf salt dome facility which was acquired in 2010. Bobcat is strategically located on the Gulf Coast near Henry Hub, interconnecting with five major interstate pipelines, including Texas Eastern. Bobcat s storage capacity is expected to be 46 Bcf by the end of 2016 when fully developed.

Steckman Ridge

We have a 50% investment in Steckman Ridge, a 12 Bcf depleted reservoir storage facility located in south central Pennsylvania that interconnects with the Texas Eastern and Dominion Transmission, Inc. systems. Steckman Ridge, which began operations in 2009, is operated by us and owned 50% by us and 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, levels 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 for 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, injected or withdrawn, which is intended 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.

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DISTRIBUTION

We provide distribution services in Canada through our subsidiary, Union Gas Limited (Union Gas). Union Gas is a major Canadian natural gas storage, transmission and distribution company based in Ontario with over 100 years of experience and service to customers. The distribution business serves approximately 1.4 million residential, commercial and industrial customers in more than 400 communities across northern, southwestern and eastern Ontario. Union Gas storage and transmission business offers storage and transportation services to customers at Dawn Hub, the largest underground storage facility in Canada and one of the largest in North America. It offers customers an important link in the movement of natural gas from Western Canada and U.S. supply basins to markets in central Canada and the northeast United States.

Union Gas distribution system consists of approximately 39,000 miles of 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 160 Bcf in 23 underground facilities located in depleted gas fields. Its transmission system consists of approximately 3,000 miles of high-pressure pipeline and associated mainline compressor stations.

Competition

Union Gas distribution system 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 is not generally subject to third-party competition within its distribution franchise area. However, physical bypass of Union Gas system may be permitted, even within Union Gas distribution franchise area. In addition, other companies could enter Union Gas markets or regulations could change.

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The incentive regulation framework approved by the OEB in 2008 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 Union Gas remained unchanged throughout the five-year incentive regulation period (2008-2012). As 2012 was the final year of Union Gas current multi-year incentive regulation framework, Union Gas filed an application with the OEB for new rates for 2013 based on traditional cost of service regulation.

This rate setting process resulted in an average annual impact on a customer s total bill ranging from 0%-6% depending on their location and customer class. The draft rate order was filed with the OEB in December 2012, and approved in January 2013. Union Gas implemented the approved OEB rate order in February 2013. Union Gas expects to file its application and evidence for another incentive regulation framework with the OEB during 2013.

Union Gas provides storage services to customers outside its franchise area and new storage services under a framework established by the OEB that supports unregulated storage investments and allows Union Gas to compete with third-party storage providers on bases of price, terms of service, and flexibility and reliability of service. Under that framework, Union Gas was required to share its long-term storage margins with ratepayers until 2011. Existing storage services to customers within Union Gas franchise area, however, have continued to be provided at cost-based rates and are not subject to third-party competition.

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 weather, price changes, the availability of natural gas and other forms of energy, the level of business activity, conservation, legislation, governmental regulations, the ability to convert to alternative fuels, and other factors.

Customers and Contracts

Most of Union Gas power generation customers, 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 from the sale of the natural gas commodity, gas distribution margins are not affected by either the source of customers gas supply or its price, except to the extent that prices affect actual customer usage.

Union Gas provides its in-franchise customers with regulated distribution, transmission and storage services. Union Gas also provides unregulated natural gas storage and regulated 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.

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WESTERN CANADA TRANSMISSION & PROCESSING

Our Western Canada Transmission & Processing business is comprised of the BC Pipeline and BC Field Services operations, and the Canadian Midstream and NGL Marketing operations.

BC Pipeline and BC Field Services provide fee-based 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. BC Pipeline 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 1,750 miles of transmission pipeline in BC and Alberta, as well as associated mainline compressor stations. Throughput for the BC Pipeline totaled 662 TBtu in 2012, compared to 713 TBtu in 2011 and 627 TBtu in 2010.

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 six gas processing plants located in BC, associated 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 700 miles of gathering pipelines. This business is primarily regulated by the province where the assets are located, either BC or Alberta.

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 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 business. The Empress extraction and fractionation plant is located in Empress, Alberta.

Fort Nelson Expansion. In 2009, firm contracts for approximately 800 MMcf/d were signed for incremental gathering and processing services in the Fort Nelson area of northeastern British Columbia. The Fort Nelson expansion program, the largest of our expansion projects in western Canada, consists of a series of 10 discrete gathering and processing projects, with a total projected capital expenditure of approximately $1 billion. Nine of the ten projects were placed in service in 2009 and 2010. The new 250 MMcf/d Fort Nelson North processing facility, which is the final phase and most significant capital outlay of the program, is under construction and is expected to be brought in service in the first quarter of 2013. Upon completion, we will operate over 1.2 Bcf/d of raw gas processing capacity and associated gathering pipelines in the Fort Nelson area.

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. 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, levels 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 that Western Canada Transmission & Processing serves.

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 product sales markets we serve. Declines in eastbound flows of natural gas through Empress and competitive market pressure continue to cause an increase in the premiums that we pay to shippers to extract NGLs compared with historical premiums paid.

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 in the 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 fee-for-service contracts which do not expose us to direct commodity-price risk. However, a sustained decline in natural gas prices has impacted our ability to negotiate and renew expiring service contracts with customers in certain areas of our operations. The BC Field Services and Canadian Midstream operations provide both firm and interruptible services.

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The NGL extraction operation at Empress, Alberta is jointly owned with a partner and has capacity to produce approximately 63,000 barrels of NGLs per day (Bbls/d) (our share is approximately 58,000 Bbls/d at full capacity). 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 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. The majority of propane is sold to propane retailers. Butane is sold mainly into the motor gasoline refinery market and condensate sales are sold to the crude blending and crude diluent markets. Profit margins are driven by the market prices of NGL products, extraction premiums paid to shippers, shrinkage make-up natural gas prices and other operating costs.

Operating results at Empress are significantly affected by changes in average NGL and natural gas prices, which have fluctuated significantly over the last several years. We continue to closely monitor the risks associated with these price changes.

FIELD SERVICES

Field Services consists of our 50% investment in DCP Midstream, which is accounted for as an equity investment. DCP Midstream gathers, processes, treats, compresses, transports and stores natural gas. In addition, DCP Midstream also fractionates, transports, gathers, processes, stores, markets and trades NGLs. Phillips 66 owns the remaining 50% interest in DCP Midstream. DCP Midstream currently owns a 28% interest in DCP Midstream Partners, LP (DCP Partners), a master limited partnership. As its general partner, DCP Midstream accounts for its investment in DCP Partners as a consolidated subsidiary.

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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, one natural gas storage facility and one NGL 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 63,000 miles of gathering and transmission pipeline.

As of December 31, 2012, DCP Midstream owned or operated 62 natural gas processing plants, which separate raw natural gas that has been gathered on DCP Midstream s and third-party systems into condensate, NGLs and residue gas.

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. As of December 31, 2012, DCP Midstream owned or operated 12 fractionators. In addition, DCP Midstream operates a propane wholesale marketing business in the northeastern United States.

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 9 Bcf Spindletop natural gas storage facility located near Beaumont, Texas.

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

DCP Midstream s operating results are significantly affected by changes in average NGL, natural gas and crude oil prices, which have fluctuated significantly over the last several years. DCP Midstream closely monitors the risks associated with these price changes. See Part II. 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, processing, transporting and storing natural gas, as well as producing, marketing and transporting NGLs, DCP Midstream competes with major integrated oil companies, major interstate and intrastate pipelines, national and local natural gas gatherers and processors, NGL transporters and brokers, marketers and distributors of natural gas supplies. Competition for natural gas supplies is based mostly on the reputation, efficiency and reliability of operations, the availability of gathering and transportation to high-demand markets, 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 mostly upon reliability, services offered and the prices of delivered natural gas and NGLs.

Customers and Contracts

DCP Midstream sells a portion of its residue gas to ConocoPhillips and sells a portion of its NGLs to Phillips 66 and Chevron Phillips Chemical Company LLC. In addition, DCP Midstream purchases natural gas from and provides gathering, transportation and other services to ConocoPhillips. Approximately 40% of its NGL production is committed to Phillips 66 and Chevron Phillips Chemical Company LLC under an existing 15-year contract, which expires in 2015. Should the contract not be renegotiated or renewed, it provides for a

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five-year ratable wind-down period through 2020. The NGL contract also grants Phillips 66 the right to purchase, at index-based prices, certain quantities of NGLs produced at processing plants that are acquired and/or constructed by DCP Midstream in the future in various counties in the Mid-Continent and Permian Basin regions, and the Austin Chalk area. DCP Midstream anticipates continuing to purchase and sell commodities with ConocoPhillips as a third-party and with Phillips 66 and Chevron Phillips Chemical Company LLC as related parties, in the ordinary course of business.

The residual natural gas, primarily methane, that results from processing raw natural gas is sold at market-based prices to marketers and end-users, including 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. More than 70% of the volumes of gas that are gathered and processed are under percentage-of-proceeds contracts.

Percentage-of-proceeds/index arrangements. In general, DCP Midstream purchases natural gas from producers at the wellhead or other receipt points, gathers the wellhead natural gas through its gathering system, treats and processes it, and then sells the residue natural gas and NGLs based on index prices from published index market prices. DCP Midstream remits to the producers either an agreed-upon percentage of the actual proceeds received from the sale of the residue natural gas and NGLs, or an agreed-upon percentage of the proceeds based on index-related prices for natural gas and NGLs regardless of the actual amount of sales proceeds which DCP Midstream receives. Certain of these arrangements may also result in DCP Midstream returning all or a portion of the residue natural gas and/or the NGLs to the producer in lieu of returning sales proceeds. DCP Midstream s revenues from percentage-of-proceeds/index arrangements relate directly with the prices of natural gas, crude oil and/or NGLs.

Fee-based arrangements. DCP Midstream receives a fee or fees for one or more of the following services: gathering, processing, compressing, treating, storing or transporting natural gas, and fractionating, storing and transporting NGLs. Fee-based arrangements include natural gas purchase arrangements pursuant to which DCP Midstream purchases natural gas at the wellhead or other receipt points at an index-related price at the delivery point less a specified amount, generally the same as the fees it would otherwise charge for gathering the natural gas from the wellhead location to the delivery point. The revenue DCP Midstream earns from these arrangements is directly related to the volume of natural gas or NGLs that flow through its systems and is not directly dependent on commodity prices. However, to the extent that a sustained decline in commodity prices results in a decline in volumes, DCP Midstream s revenues from these arrangements could be reduced.

Keep-whole and wellhead purchase arrangement. DCP Midstream gathers raw natural gas from producers for processing, markets the NGLs, and returns to the producer residual natural gas with a Btu content equivalent to the Btu content of the natural gas gathered. This arrangement keeps the producer whole to the thermal value of the natural gas received. Under the terms of a wellhead purchase contract, DCP Midstream purchases natural gas from the producer at the wellhead or defined receipt point for processing and markets the resulting NGLs and residue gas at market prices. DCP Midstream is exposed to the difference between the value of the NGLs extracted from processing and the value of the Btu-equivalent of the residue natural gas, or frac spread. Under these types of contracts, DCP Midstream benefits in periods when NGL prices are higher relative to natural gas prices.

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. The revenues that DCP Midstream earns from the sale of condensate correlate directly with crude oil prices.

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OTHER

Sand Hills / Southern Hills. In November 2012, Spectra Energy acquired direct one-third ownership interests in DCP Sand Hills Pipeline, LLC (Sand Hills) and DCP Southern Hills Pipeline, LLC (Southern Hills). DCP Midstream and Phillips 66 also each own a direct one-third interest in the two pipelines. With our direct ownership interests and our 50% ownership interest of DCP Midstream, we have 50% effective ownership interests in Sand Hills and Southern Hills. The Sand Hills and Southern Hills NGL pipelines are currently under construction by DCP Midstream, which will operate the pipelines upon completion.

The Sand Hills pipeline will consist of approximately 720 miles of pipeline with initial capacity of 200,000 Bbls/d that will provide NGL transportation from the Permian Basin and Eagle Ford shale region to the premium NGL markets on the Gulf Coast. The Sand Hills pipeline is being phased into service, with Phase I completed during the fourth quarter of 2012, with initial service from the Eagle Ford shale region to Mont Belvieu. Phase II, which will provide service from the Permian Basin to the Eagle Ford shale region, is expected to be completed in the second quarter of 2013. The Southern Hills pipeline will consist of approximately 800 miles of NGL pipeline with initial capacity of almost 150,000 Bbls/d. The Southern Hills pipeline will be connected to several DCP Midstream processing plants and anticipated third-party producers and will provide NGL transportation from the Mid-Continent to Mont Belvieu. The Southern Hills pipeline is expected to be in-service in mid-2013.

Our direct one-third equity investments in Sand Hills and Southern Hills are currently not included within any of our reportable segments and are classified within Other. These investments will be moved to a new operating segment, Liquids, along with the Express-Platte Pipeline system assets, upon the close of the acquisition of the Express-Platte Pipeline system assets. See Note 3 of Notes to Consolidated Financial Statements for discussion of the pending acquisition of the Express-Platte Pipeline system assets.

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 the 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.

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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. Our Canadian operations are governed by various federal and provincial agencies with respect to pipeline safety, including the NEB and the Transportation Safety Board, the British Columbia Oil and Gas Commission, the Alberta Energy Resources Conservation Board and the Ontario Technical Standards and Safety Authority.

The Canadian 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 our Canadian Midstream operations for gathering and processing services in western Canada are regulated on a complaints-basis by applicable provincial regulators. Our Empress NGL businesses are not under any form of rate regulation.

The intrastate natural gas and NGL pipelines owned by us and DCP Midstream are subject to state regulation. To the extent that the natural gas intrastate pipelines that transport natural gas in interstate commerce provide services under Section 311 of the Natural Gas Policy Act of 1978, they are subject to FERC regulation. DCP Midstream s interstate natural gas pipeline operations are also subject to regulation by the FERC. 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 federal and provincial regulations, regarding air and water quality, hazardous and solid waste disposal and other environmental matters.

Environmental laws and regulations affecting our U.S.-based operations 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, like 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) amended parts of the Clean Water Act and other statutes as they pertain to the prevention of and response to oil spills. The OPA imposes certain spill prevention, control and countermeasure requirements. Although we are primarily a natural gas business, the 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 therefore have CERCLA liabilities.

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- 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 effects of proposed projects are a factor in determining whether we will be permitted to complete proposed projects.

Environmental laws and regulations affecting our Canadian-based operations include, but are not limited to:

- 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 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, requires the reporting of greenhouse gas (GHG) emissions from our operations in Canada. Additional regulations to be promulgated under this 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 required 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 Part II. Item 8. Financial Statements and Supplementary Data, Notes 5 and 19 of Notes to Consolidated Financial Statements.

Except to the extent discussed in Notes 5 and 19, 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 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 Part II. 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 18 of Notes to Consolidated Financial Statements.

Employees

We had approximately 5,600 employees as of December 31, 2012, including approximately 3,500 employees in Canada. In addition, DCP Midstream employed approximately 3,200 employees as of such date. Approximately 1,400 of our Canadian employees are subject to collective bargaining agreements governing their employment with us. Approximately 20% of those employees are covered under agreements that either have expired or will expire by December 31, 2013.

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Executive and Other Officers

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

Name	Age	Position
Gregory L. Ebel	48	President and Chief Executive Officer, Director
J. Patrick Reddy	60	Chief Financial Officer
Dorothy M. Ables	55	Chief Administrative Officer
John R. Arensdorf	62	Chief Communications Officer
Alan N. Harris	59	Chief Development and Operations Officer
Reginald D. Hedgebeth	45	General Counsel
Guy G. Buckley	52	Group Vice President and Treasurer
Allen C. Capps	42	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 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 Chief Ethics and Compliance Officer from January 2007.

John R. Arensdorf assumed his current position in November 2008. He previously served as Vice President, Investor Relations from January 2007.

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.

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.

Guy G. Buckley assumed his current position as Group Vice President and Treasurer in January 2012. He previously served as Group Vice President, Corporate Development and Strategy since December 2008 and was Vice President Mergers and Acquisitions from January 2007 to December 2008.

Allen C. Capps assumed his current position as Vice President and Controller in January 2012. He previously served as Vice President, Business Development, Storage and Transmission, for Union Gas from April 2010. Prior to then, Mr. Capps served as Vice President and Treasurer for Spectra Energy Corp from December 2007 until April 2010.

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, proxy statements and amendments to such reports. The public may read and copy any materials that we file with the SEC at the SEC s Public

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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 material 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, such as 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 and transmission businesses 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 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 on the development of natural gas supplies, 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 affect our revenues, earnings and cash flows.

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

We are exposed to foreign currency risk from our Canadian operations. An average 10% devaluation in the Canadian dollar exchange rate during 2012 would have resulted in an estimated net loss on the translation of

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local currency earnings of approximately $41 million on our Consolidated Statement of Operations. In addition, if a 10% devaluation had occurred on December 31, 2012, the Consolidated Balance Sheet would have been negatively impacted by $676 million through a cumulative translation adjustment in Accumulated Other Comprehensive Income (AOCI). At December 31, 2012, one U.S. dollar translated into 0.99 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 affect cash flows 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, NGL processing and marketing, and market-based storage 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 exposed to market price fluctuations of NGLs and natural gas primarily in Field Services and at Empress, and to oil primarily in our Field Services segment. The effect of commodity price fluctuations to our earnings could be material.

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, including possible declines, as contracts renew.

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 United States 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 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 and to maintain those approvals and permits issued and satisfy the terms and conditions imposed therein;

- the availability of skilled labor, equipment, and materials to complete expansion projects;

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potential changes in federal, state and local statutes and regulations, including environmental requirements, that may 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 cost. As a result, new facilities may not achieve their expected investment return, which could affect our earnings, financial position and 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, storage, and distribution activities, such as leaks, explosions, mechanical problems, activities of third parties and damage to pipelines, facilities and equipment caused by hurricanes, tornadoes, floods, fires and other natural disasters, that could cause substantial financial losses. In addition, these risks could result in significant injury, loss of 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 effect on our business, earnings, financial condition and cash flows.

We are subject to pipeline safety laws and regulations, compliance with which may require significant capital expenditures, increase our cost of operations and affect or limit our business plans.

Our interstate pipeline operations are subject to pipeline safety regulation administered by the Pipeline and Hazardous Materials Safety Administration (PHMSA) of the U.S. Department of Transportation. These laws and regulations require us to comply with a significant set of requirements for the design, construction, maintenance and operation of our interstate pipelines. These regulations, among other things, include requirements to monitor and maintain the integrity of our pipelines. The regulations determine the pressures at which our pipelines can operate.

In 2010, serious pipeline incidents on systems unrelated to ours focused the attention of Congress and the public on pipeline safety. Legislative proposals have been introduced in Congress that would strengthen the PHMSA s enforcement and penalty authority, and expand the scope of its oversight. In August 2011, PHMSA initiated an Advance Notice of Proposed Rulemaking announcing its consideration of substantial revisions in its regulations to increase pipeline safety. PHMSA also has issued guidance that states it will focus near-term enforcement efforts on recordkeeping and integrity management following urgent recommendations by the National Transportation Safety Board related to pipeline pressure and recordkeeping. On January 3, 2012, the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 was signed into law. This Act (the 2012 PSA Amendments) amends the Pipeline Safety Act in a number of significant ways, including:

Authorizing PHMSA to assess higher penalties for violations of its regulations,

Requiring PHMSA to adopt appropriate regulations within two years requiring the use of automatic or remote-controlled shutoff valves on new or rebuilt pipeline facilities and to perform a study on the application of such technology to existing pipeline facilities in High Consequence Areas (HCAs),

- Requiring operators of pipelines to verify maximum allowable operating pressure and report exceedances within five days,

- Requiring PHMSA to study and report on the adequacy of soil cover requirements in HCAs, and

- Requiring PHMSA to evaluate in detail whether integrity management requirements should be expanded to pipeline segments outside of HCAs (where the requirements currently apply).

These legislative changes, when implemented, will impose additional costs on new pipeline projects as well as on existing operations. It is still uncertain what regulatory changes PHMSA will propose as a result of the Advance Notice of Proposed Rulemaking, but PHMSA has begun to undertake the various requirements imposed on it by the 2012 PSA Amendments. In this climate of increasingly stringent regulation, pipeline failures or failures to comply with applicable regulations could result in reduction of allowable operating pressures as authorized by PHMSA, which would reduce available capacity on our pipelines. Should any of these risks materialize, it may have a material effect on our operations, earnings, financial condition and cash flows.

We are subject to numerous environmental laws and regulations, compliance with which can require significant capital expenditures, 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. We currently estimate that compliance with major Clean Air Act regulatory programs will cause us to incur capital expenditures of approximately $450 million through 2020 to obtain permits, evaluate offsite impacts of our operations, install pollution control equipment, and otherwise assure compliance. The precise nature of these compliance obligations at each of our facilities has not been finally determined and may depend in part on future regulatory changes. In addition, compliance with new and emerging environmental regulatory programs is likely to significantly increase our operating costs compared to historical levels.

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 operations 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 may be incurred to comply with environmental regulations in the future will not have a material effect on our earnings and cash flows.

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 expired in 2012 and had not been signed by the United States. United Nations-sponsored international negotiations were held in Durban, South Africa in December 2011 with the intent of defining a future agreement for 2012 and beyond. A non-binding agreement was reached to develop a roadmap aimed at creating a global agreement on climate action to be implemented by 2020.

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The United States is a party to the Durban agreement. In the interim period before 2020, the Kyoto Protocol will continue in effect, although it is expected that not all of the current parties will choose to commit for this extended period.

In the United States, climate change action is evolving at state, regional and federal levels. Pursuant to federal law, we are currently subject to an obligation to report our GHG emissions, but are not currently subject to limits on emissions of GHGs. 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. However, as the key details of future GHG restrictions and compliance mechanisms remain undefined, the likely future effects on our business are highly uncertain.

In May 2010, the EPA issued the Prevention of Significant Deterioration (PSD) and Title V Greenhouse Gas Tailoring Rule (Tailoring Rule). This regulation establishes that the construction of new or modification of existing major sources of GHG emissions would become subject to the PSD air permitting program (and later, the Title V permitting program) beginning in January 2011, although the regulation also significantly increases the emissions thresholds that would subject facilities to these regulations. In June 2012, these regulations, along with other GHG regulations and determinations issued by the EPA, were upheld by the D.C. Circuit of Appeals. In July 2012, the EPA determined in Step 3 of the Tailoring Rule process that it would maintain the current GHG emissions thresholds for PSD and Title V applicability. This rule has also been appealed. We anticipate that in the future, new capital projects or modification of existing projects could be subject to a permit requirement related to GHG emissions that may result in delays in completing such projects.

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 or regulation 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 earnings, 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 earnings and cash flows.

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 affected, particularly if we or our rated subsidiaries are unable to maintain an investment-grade credit rating, which could 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 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. Consequently, 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.

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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 affect cash flows or restrict business. Furthermore, if Spectra Energy s short-term debt rating were to be below tier 2 (for example, A-2 for Standard and Poor s, P-2 for Moody s Investor Service and F2 for Fitch Ratings), access to the commercial paper market could be significantly limited. Although this would not affect our ability to draw under our credit facilities, borrowing costs could be significantly higher.

If we are not able to access capital at competitive rates, our ability to finance operations and implement our strategy may be 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 renewals of long-term transportation agreements, which could expose our transportation volumes and revenues to increased volatility.

We may be unable to secure renewals of long-term transportation agreements in the future for our natural gas transmission business as a result of economic factors, lack of commercial gas supply available to our systems, changing gas supply flow patterns in North America, 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 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 90% of our credit exposures for transportation, storage, and gathering and processing services are with customers who have an investment-grade rating (or the equivalent based on our evaluation) or are secured by collateral. 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 effect on our earnings and cash flows.

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 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 effect on natural gas production in British Columbia and Alberta,

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which could have a material 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-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 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 high for companies, like us, operating in any energy infrastructure industry that handle volatile gaseous and liquid hydrocarbons. The potential for terrorism, including cyber-terrorism, has subjected our operations to increased risks that could have a material 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 affect our business and cash flows.

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 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, 2012, 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 15 of Notes to Consolidated Financial Statements, none of our properties were secured by mortgages or other material security interests at December 31, 2012.

Our corporate headquarters are located at 5400 Westheimer Court, Houston, Texas 77056, which is a leased facility. The lease expires in 2026. 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.

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Item 3. Legal Proceedings.

We have no material pending legal proceedings that are required to be disclosed hereunder. See Note 19 of Notes to Consolidated Financial Statements for discussions of other legal proceedings.

Item 4. Mine Safety Disclosures.

Not applicable.

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 January 31, 2013, there were approximately 127,000 holders of record of our common stock and approximately 472,000 beneficial owners.

Common Stock Data by Quarter

	Dividends Per	Stock Price Range (a)	
2012	**Common Share**	**High**	**Low**
First Quarter	$ 0.28	$ 32.27	$ 30.17
Second Quarter	0.28	31.79	27.36
Third Quarter	0.28	31.00	28.02
Fourth Quarter	0.305	30.22	26.55
2011			
First Quarter	0.26	27.50	24.44
Second Quarter	0.26	29.24	26.17
Third Quarter	0.26	28.00	22.80
Fourth Quarter	0.28	31.33	23.17

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

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Stock Performance Graph

The following graph reflects the comparative changes in the value from January 1, 2008 through December 31, 2012 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 1,	December 31,				
	2008	2008	2009	2010	2011	2012
Spectra Energy Corp	$ 100.00	$ 63.70	$ 88.10	$ 112.29	$ 143.78	$ 133.09
S&P 500 Stock Index	100.00	63.00	79.68	91.68	93.61	108.59
S&P 500 Storage & Transportation Index	100.00	49.70	69.45	88.48	130.87	146.90

Dividends

Our near-term objective is to increase our cash dividend by at least $0.08 per year through 2014. In the long-term, we anticipate paying dividends at an average payout ratio level of approximately 65% of our 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. The declaration and payment of dividends is 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.

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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.

	2012	2011	2010 (Unaudited)	2009	2008
	(dollars in millions, except per-share amounts)				
Statements of Operations					
Operating revenues	$ 5,075	$ 5,351	$ 4,945	$ 4,552	$ 5,074
Operating income	1,575	1,763	1,674	1,475	1,480
Income from continuing operations	1,045	1,257	1,123	919	1,195
Net income noncontrolling interests	107	98	80	75	65
Net income controlling interests	940	1,184	1,049	849	1,132
Ratio of Earnings to Fixed Charges	2.8	3.4	3.1	2.8	3.6
Common Stock Data					
Earnings per share from continuing operations					
Basic	$ 1.44	$ 1.78	$ 1.61	$ 1.31	$ 1.82
Diluted	1.43	1.77	1.60	1.31	1.81
Earnings per share					
Basic	1.44	1.82	1.62	1.32	1.82
Diluted	1.43	1.81	1.61	1.32	1.81
Dividends per share	1.145	1.06	1.00	1.00	0.96

	2012	2011	December 31, 2010 (Unaudited)	2009	2008
	(in millions)				
Balance Sheets					
Total assets	$ 30,587	$ 28,138	$ 26,686	$ 24,091	$ 21,924
Long-term debt including capital leases, less current maturities	10,653	10,146	10,169	8,947	8,290

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 2012, we continued to successfully execute the long-term strategies we outlined for our shareholders meeting the needs of our customers, generating strong earnings and cash flows from our fee-based assets, executing capital expansion plans that underlie our growth objectives, and maintaining a strong balance sheet. These results, combined with future growth opportunities, led our Board of Directors to approve an increase in our quarterly dividend effective with the fourth quarter of 2012 to $0.305 per share, or $1.22 annually, representing a $0.025 increase from the third-quarter annual level. The new dividend level represents a nearly 9% increase over the previous level. Our near-term objective is to increase our cash dividend by at least $0.08 per year through 2014. In the long-term, we anticipate paying dividends at an average payout ratio level of approximately 65% of our net income from controlling interests per share of common stock.

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Our fee-based assets continued to perform well during 2012. In addition, our gathering and processing business at Field Services generated higher earnings. These favorable results helped to partially offset lower commodity prices at Field Services and lower NGL sales prices related to the Empress NGL business at Western Canada Transmission & Processing.

We reported net income from controlling interests of $940 million, and $1.43 of diluted earnings per share for 2012 compared to net income from controlling interests of $1,184 million, and $1.81 of diluted earnings per share for 2011.

Earnings highlights for 2012 include the following:

- U.S. Transmission s earnings benefited from expansion projects and lower operating costs, partially offset by lower processing revenues, anticipated lower storage revenues, lower rates and contract reduction,

- Distribution s earnings decreased mostly as a result of an unexpected decision by the OEB affecting transportation revenues and lower customer usage due to warmer weather, partially offset by higher short-term transportation service revenues and lower earnings to be shared with customers,

- Western Canada Transmission & Processing s results reflected a net loss in the Empress NGL business due primarily to lower NGL sales prices and lower contracted volumes from conventional areas in the gathering and processing business, partially offset by higher gathering and processing earnings from expansions, and

- Field Services earnings decreased mostly due to lower commodity prices, partially offset by a reduction in depreciation expense attributable to an increase in the remaining useful lives of gathering, transmission, processing, storage and other assets and higher gathering and processing volumes from asset growth in 2012 and the absence of severe weather which restricted volumes in 2011.

We invested $2.0 billion of capital expenditures in 2012, including approximately $1.3 billion of expansion capital expenditures. In addition, we invested $0.5 billion for our initial and subsequent investments in Sand Hills and Southern Hills, which we have classified as investment expenditures. Successful execution of our 2012 projects allowed us to continue to achieve aggregate returns over the last six years consistent with 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 continue to foresee significant expansion capital spending over the next several years, with approximately $1.4 billion planned for 2013, as we execute on identified opportunities leveraging our asset footprint to capture incremental growth connecting large diverse markets with growing supply throughout North America.

We are committed to an investment-grade balance sheet and continued prudent financial management of our capitalization structure. Therefore, financing these growth activities will continue to be based on our strong, and growing, fee-based earnings and cash flows as well as the issuance of long-term debt. In 2013, we plan to issue approximately $3.3 billion of combined long-term debt and commercial paper, including the refinancing of approximately $0.9 billion of long-term debt maturities. In addition, as part of our overall financial management, we have ongoing access to approximately $1.6 billion under our revolving credit facilities as of December 31, 2012, to be utilized as needed for effective working capital management. At December 31, 2012, our debt-to-capitalization ratio is at 56%. This leverage ratio benefited from earnings and the issuance of additional shares of common stock in 2012.

In November 2012, we acquired direct one-third ownership interests in Sand Hills and Southern Hills for an aggregate $459 million, both of which are currently under construction by DCP Midstream. DCP Midstream and Phillips 66 also each own direct one-third interests in the two pipelines. See Note 3 of Notes to Consolidated Financial Statements for further discussion.

In November 2012, Spectra Energy Partners issued 5.5 million common units to the public, representing limited partner interests, and 0.1 million general partner units to Spectra Energy. Total net proceeds to Spectra Energy Partners were $148 million (net proceeds to Spectra Energy were $145 million), used to fund capital expenditures and acquisitions. See Note 2 of Notes to Consolidated Financial Statements for further discussion.

In December 2012, we entered into a definitive agreement to purchase 100% of the ownership interests in the Express-Platte Pipeline System for $1.49 billion, consisting of $1.25 billion cash and $240 million of acquired debt. The transaction is expected to close in the first half of 2013. See Note 3 of Notes to Consolidated Financial Statements for further discussion.

In December 2012, we issued 14.7 million shares of our common stock and received net proceeds of $382 million to fund acquisitions and capital expenditures and for other general corporate purposes.

Our Strategy. Our focus is on leading the natural gas infrastructure industry in terms of safe and reliable operations, customer responsiveness and profitability. Through our network of people and assets, we will increase our size, financial flexibility and services to meet the changing needs of our customers. 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 2012 strategies:

- Deliver on our 2013 financial commitments.
- Effectively execute our 2013 expansion plans.
- Leverage our asset footprint to develop new growth opportunities.
- Expand our value chain participation into complementary infrastructure assets.

Natural gas supply dynamics continue to rapidly change and strengthen, and there is growing long-term potential for natural gas to be an effective solution for meeting the energy needs of North America. This causes us to be optimistic about future growth opportunities. Identified opportunities include conversions of coal-fired generation plants that are in close proximity to our pipelines in the southeastern and northeastern United States to natural gas-fired generation, the attachment of shale supplies to attractive markets, incremental gathering and processing requirements in western Canada, potential LNG exports from North America to Asia and other continents, and significant new liquids pipeline infrastructure, and gathering and processing facilities in our Field Services segment. With our advantage of providing access to strong supply regions as well as growing natural gas and liquids markets, we expect to continue expanding our assets and operations to meet these needs.

In late 2012, we acquired direct one-third ownership interests in Sand Hills and Southern Hills, and signed a definitive agreement to purchase the Express-Platte Pipeline system assets which transport crude oil from western Canada to refining markets in the United States. The Express-Platte Pipeline acquisition is expected to close in the first half of 2013. These acquisitions, when completed, provide opportunities to further move into adjacent businesses with similar customer bases and expand our value chain participation into NGL pipeline and crude oil infrastructure assets.

Successful execution of our strategy will be determined by such key factors as the continued successful production and the consumption of natural gas within the U.S. and Canada, our ability to provide creative solutions for customers energy needs as they evolve, and continued cost control and successful execution on capital projects.

We continue to be actively engaged in the national discussions in both the U.S. and Canada regarding the potential for natural gas to be a key component of a long-term energy solution for North America. Consistent with our key role in this solution, we are committed to operating all of our assets safely and reliably for our employees, the communities in which we operate and our customers. And we have taken a lead role in supporting natural gas pipeline safety legislation.

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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 prolonged decreases in the demand for natural gas and/or 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. Lower overall economic output would cause a decline in the volume of natural gas distributed or gathered and processed at our plants, resulting in lower earnings and cash flows. This decline would mostly affect distribution revenues and gathering revenues, potentially 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. Gathering and processing revenues and the earnings and cash 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. While experiencing a decline in production from conventional gas wells, natural gas exploration and drilling activity in the areas that affect our Western Canada Transmission & Processing and Field Services segments remain strong, primarily driven by recent positive developments around unconventional gas reserves production in numerous locations within North America as discussed further below.

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 continental United States 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 natural gas reserves in western and eastern Canada. The national supply profile is shifting to new sources of gas from natural gas shale basins in the Rockies, Mid-Continent, Appalachia, Texas and Louisiana. Also, significant supply sources continue to be identified for development in western Canada. 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. Recent community and political pressures have arisen around the production processes associated with extracting natural gas from the natural gas shale basins. Although we continue to believe that natural gas will remain a viable energy solution for the U.S. and Canada, these pressures could increase costs and/or cause a slowdown in the production of natural gas from these basins, and therefore, could negatively affect our growth plans.

Natural gas storage prices have recently been challenged as a result of increasing natural gas supply and narrower seasonal price spreads. Gas supply and demand dynamics continue to change as a result of the development of new unconventional shale gas supplies. These market factors will continue to keep downward pressure on storage values in the near term.

While current drilling levels are below recent historical averages, the relatively higher productivity of unconventional wells has led to increased production supporting continued growth of Western Canada Transmission & Processing s gathering and processing business in the areas of British Columbia and Alberta where unconventional gas development is prevalent.

In certain areas of Western Canada Transmission & Processing s operations served by conventional supply, lower natural gas prices resulting from increasing North American gas production, primarily unconventional, have reduced producer demand for expansions of the British Columbia conventional gas processing plants as well as renewals of existing gas processing contracts, and could continue to do so as long as gas prices remain below historical norms.

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Our businesses in the United States and Canada are subject to regulations on the federal, state and provincial levels. 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. During the past several years, the Canadian dollar has fluctuated compared to the U.S. dollar, which affected earnings to varying degrees for very short periods. Changes in the exchange rate or any other factors are difficult to predict and may affect our future results.

Certain of our earnings are affected by fluctuations in commodity prices, especially the earnings of DCP Midstream and our Empress NGL business in Western Canada Transmission & Processing, which are most sensitive to changes in NGL prices. We evaluate, on an ongoing basis, the risks associated with commodity price volatility and currently have no material commodity hedges in place. We continue to evaluate various alternatives to address market uncertainties due to commodity price volatility.

Based on current projections, our expected effective income tax rate will approximate 23% 24% for 2013. Our overall expected tax rate largely depends on the proportion of earnings in the United States to the earnings of our Canadian operations. Our earnings in the U.S. are subject to a combined federal and state statutory tax rate of approximately 37%. Our earnings in Canada are subject to a combined federal and provincial statutory tax rate of approximately 26%, but we anticipate an effective Canadian tax rate of approximately 3% for 2013, driven primarily by the recognition of certain regulatory tax benefits and an expected tax reserve release. See Liquidity and Capital Resources for further discussion about the tax impact of repatriating funds generated from our Canadian operations to Spectra Energy Corp (the U.S. parent).

Our strategic objectives include a critical focus on capital expansion projects that will require access to capital markets. An inability to access capital at competitive rates could affect our ability to implement our strategy. Market disruptions or a downgrade in our credit ratings may increase the cost of borrowings or 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, the pricing of materials and challenges associated with ensuring the protection of our environment and continual safety enhancements to our facilities. We maintain a strong 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.

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RESULTS OF OPERATIONS

	2012	2011	2010
		(in millions)	
Operating revenues	$ 5,075	$ 5,351	$ 4,945
Operating expenses	3,502	3,596	3,281
Gains on sales of other assets and other, net	2	8	10
Operating income	1,575	1,763	1,674
Other income and expenses	465	606	462
Interest expense	625	625	630
Earnings from continuing operations before income taxes	1,415	1,744	1,506
Income tax expense from continuing operations	370	487	383
Income from continuing operations	1,045	1,257	1,123
Income from discontinued operations, net of tax	2	25	6
Net income	1,047	1,282	1,129
Net income noncontrolling interests	107	98	80
Net income controlling interests	$ 940	$ 1,184	$ 1,049

2012 Compared to 2011

Operating Revenues. The $276 million, or 5%, decrease was driven mainly by:

lower natural gas prices passed through to customers, a decrease in customer usage of natural gas largely due to warmer weather in 2012 and an unexpected decision by OEB in 2012 affecting transportation revenues at Distribution,

lower NGL sales prices and volumes in the Empress NGL business and a decrease in contracted volumes in the conventional gathering and processing business at Western Canada Transmission & Processing, and

anticipated lower storage revenues, lower rates, contract reductions and lower processing revenues at U.S. Transmission, partially offset by

higher revenues from expansion projects at Western Canada Transmission & Processing and U.S. Transmission.

Operating Expenses. The $94 million, or 3%, decrease was driven mainly by:

lower natural gas prices passed through to customers and lower natural gas purchased resulting from decreased volumes in natural gas sold primarily due to warmer weather in 2012 at Distribution, and

- lower equipment repairs and maintenance expenses, pipeline integrity costs, employee benefits and other costs, net of accelerated amortization of software at U.S. Transmission, partially offset by

- higher depreciation and amortization from expansion projects placed in service at Western Canada Transmission & Processing and U.S. Transmission.

Operating Income. The $188 million decrease was attributable to a net loss in the Empress NGL business primarily due to lower NGL sales prices related to the Empress NGL business and lower contracted volumes from conventional areas in the gathering and processing business at Western Canada Transmission & Processing, and an unexpected decision by the OEB affecting prior year transportation revenues and lower customer usage of natural gas as a result of warmer weather at Distribution, partially offset by higher earnings from expansion projects at Western Canada Transmission & Processing and U.S. Transmission.

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Other Income and Expenses. The $141 million decrease was attributable to lower equity earnings from Field Services mostly due to lower commodity prices, partially offset by a reduction in depreciation expense attributable to an increase of the remaining useful lives of DCP Midstream s gathering, transmission, processing, storage and other assets in 2012 and an increase in gathering and processing margins as a result of higher volumes due to asset growth in 2012 and the impact of severe weather in the first quarter of 2011. In addition, the lower equity earnings from Field Services were partially offset by higher allowance for funds used during construction (AFUDC) due to increased capital spending on expansion projects at Western Canada Transmission & Processing and U.S. Transmission.

Income Tax Expense from Continuing Operations. The $117 million decrease was a result of lower earnings from continuing operations and a lower Canadian effective tax rate, partially offset by favorable tax adjustments in 2011. The effective tax rate for income from continuing operations was 26% in 2012 compared to 28% in 2011. The lower effective tax rate in 2012 was primarily due to a lower Canadian effective tax rate. See Note 6 of Notes to Consolidated Financial Statements for reconciliations of our effective tax rates to the statutory tax rate.

Income from Discontinued Operations, Net of Tax. The $23 million decrease was primarily attributable to lower income from propane deliveries in 2012 as a result of a final settlement of these activities in the second quarter of 2012.

Net Income Noncontrolling Interests. The $9 million increase was driven by an increase in noncontrolling ownership interests resulting from the Spectra Energy Partners public sales of additional partner units in June 2011 and November 2012, and higher earnings from Spectra Energy Partners, primarily as a result of the timing of expansion on Eastern Tennessee and the timing of the acquisition of Big Sandy in July 2011 and M&N L.L.C. in November 2012.

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

2011 Compared to 2010

Operating Revenues. The $406 million, or 8%, increase was driven mainly by:

- revenues from expansion projects at U.S. Transmission and Western Canada Transmission & Processing and the acquisitions of Bobcat and Big Sandy at U.S. Transmission,
- the effects of a stronger Canadian dollar on revenues at Distribution and Western Canada Transmission & Processing,
- an increase in customer usage of natural gas due to colder weather in 2011 at Distribution, and
- higher NGL and other petroleum products sales volumes from the Empress NGL business due to the effect of a scheduled plant turnaround in 2010, and higher NGL sales prices associated with the Empress NGL business in 2011 at Western Canada Transmission & Processing, partially offset by
- lower natural gas prices passed through to customers at Distribution.

Operating Expenses. The $315 million, or 10%, increase was driven mainly by:

- higher volumes of natural gas purchased attributable to higher demand for NGL and other petroleum products for extraction and make-up, and higher prices of natural gas purchased caused primarily by higher extraction premiums at the Empress NGL business at Western Canada Transmission & Processing, higher volumes of natural gas sold as a result of colder weather in 2011 at Distribution,

the effects of a stronger Canadian dollar at Distribution and Western Canada Transmission & Processing, and

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- higher corporate costs, partially offset by
- lower natural gas prices passed through to customers at Distribution.

Operating Income. The $89 million increase was mainly driven by higher earnings from expansion projects at U.S. Transmission and Western Canada Transmission & Processing, and the effects of a stronger Canadian dollar, partially offset by higher corporate costs.

Other Income and Expenses. The $144 million increase was attributable to higher equity earnings from Field Services mainly due to higher commodity prices, and lower interest and income tax expenses, partially offset by higher planned operating expenses.

Income Tax Expense from Continuing Operations. The $104 million increase was a result of higher earnings from continuing operations and higher effective tax rates. The effective tax rate for income from continuing operations was 28% in 2011 compared to 25% in 2010. The lower effective tax rate in 2010 was primarily due to favorable tax settlements, including an administrative change by the Canadian federal government that resulted in cash tax refunds from historical tax years and a reduction to the deferred tax liability. See Note 6 of Notes to Consolidated Financial Statements for reconciliations of our effective tax rates to the statutory tax rate.

Income from Discontinued Operations, Net of Tax. The $19 million increase reflects the 2011 recovery of losses incurred in the fourth quarter of 2010 related to a breach by a third party of certain scheduled propane deliveries to us. Higher income from propane deliveries and the recovery of losses in 2011 were offset by a favorable income tax adjustment related to previously discontinued operations in the first quarter of 2010.

Net Income Noncontrolling Interests. The $18 million increase was mainly driven by an increase in the noncontrolling interests ownership percentage resulting from the Spectra Energy Partners public sales of additional partner units in December 2010 and June 2011, and higher earnings from Spectra Energy Partners, primarily as a result of their acquisitions of an additional 24.5% in Gulfstream in the fourth quarter of 2010 and Big Sandy in July 2011.

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

Segment Results

Management evaluates segment performance based on earnings before interest and taxes (EBIT), which 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.

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Field Services gathers, processes, treats, compresses, transports and stores natural gas. In addition, Field Services also fractionates, transports, gathers, processes, stores, markets and trades NGLs. It conducts operations through DCP Midstream, which is owned 50% by us and 50% by Phillips 66. 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

	2012	2011 (in millions)	2010
U.S. Transmission	$ 995	$ 983	$ 948
Distribution	374	425	409
Western Canada Transmission & Processing	387	510	409
Field Services	279	449	335
Total reportable segment EBIT	2,035	2,367	2,101
Other	(112)	(104)	(38)
Total reportable segment and other EBIT	1,923	2,263	2,063
Interest expense	625	625	630
Interest income and other (a)	117	106	73
Earnings from continuing operations before income taxes	$ 1,415	$ 1,744	$ 1,506

(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-100%-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

	2012	2011	Increase (Decrease)	2010	Increase (Decrease)
			(in millions, except where noted)		
Operating revenues	$ 1,897	$ 1,900	$ (3)	$ 1,821	$ 79
Operating expenses					
Operating, maintenance and other	654	684	(30)	671	13
Depreciation and amortization	282	272	10	258	14
Gains on sales of other assets and other, net	3	8	(5)	11	(3)
Operating income	964	952	12	903	49
Other income and expenses	144	132	12	126	6
Noncontrolling interests	113	101	12	81	20
EBIT	$ 995	$ 983	$ 12	$ 948	$ 35

Proportional throughput, TBtu (a)	2,709	2,770	(61)	2,708	62

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

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2012 Compared to 2011

Operating Revenues. The $3 million decrease was driven by:

- a $41 million decrease from anticipated lower storage revenues, lower rates on M&N LP, and contract reductions at Texas Eastern and Ozark Gas Transmission, and
- a $24 million decrease in processing revenues associated with pipeline operations caused by lower prices, partially offset by
- a $51 million increase from expansion projects and the timing of the acquisition of Big Sandy in July 2011, and
- an $11 million increase in recoveries of electric power and other costs passed through to customers.

Operating, Maintenance and Other. The $30 million decrease was driven by:

- a $32 million decrease due to lower equipment repairs and maintenance expenses, pipeline integrity costs, employee benefits and other costs, partially offset by accelerated software amortization, and
- a $6 million decrease from project development costs expensed in 2011, partially offset by
- an $8 million increase in electric power and other costs passed through to customers.

Depreciation and Amortization. The $10 million increase was driven by expansion projects and the timing of the acquisition of Big Sandy in July 2011.

Gain on sale of other assets and other, net. The $5 million decrease was driven by 2011 customer settlements.

Other Income and Expenses. The $12 million increase was primarily due to the increase in AFUDC as a result of higher capital spending in 2012.

Noncontrolling Interests. The $12 million increase was driven by an increase in noncontrolling ownership interests resulting from the Spectra Energy Partners public sales of additional partner units in June 2011 and November 2012, and higher earnings from Spectra Energy Partners, primarily as a result of expansion on East Tennessee, and the timing of the acquisitions of Big Sandy in July 2011 and M&N LLC in November 2012 by Spectra Energy Partners.

EBIT. The $12 million increase was driven by increased earnings from expansions and lower operating costs, partially offset by lower processing revenues, anticipated lower storage revenues, lower rates at M&N LP, and contract reductions at Texas Eastern and Ozark Gas Transmission.

2011 Compared to 2010

Operating Revenues. The $79 million increase was driven by:

a $136 million increase from expansion projects and the acquisitions of Bobcat in August 2010 and Big Sandy in July 2011, partially offset by

a $24 million decrease in recoveries of electric power and other costs passed through to customers,

a $24 million decrease from lower contracted volumes and rates as a result of contract renewals mainly at Ozark Gas Transmission and Algonquin, and

a $10 million decrease in processing revenues associated with pipeline operations caused by lower volumes.

Operating, Maintenance and Other. The $13 million increase was driven by:

- a $20 million increase from acquisitions and expansion projects,
- an $11 million increase in project development costs due to $6 million of costs expensed in 2011 and $5 million capitalized in 2010 from costs that were previously expensed in 2009, and
- a $9 million increase in equipment repair and maintenance expenses, pipeline integrity costs, and software costs, partially offset by
- a $27 million decrease in electric power and other costs passed through to customers.

Depreciation and Amortization. The $14 million increase was mainly driven by expansion projects and the acquisitions of Bobcat and Big Sandy.

Other Income and Expenses. The $6 million increase was primarily due to an indemnification of a tax liability related to the Bobcat acquisition.

Noncontrolling Interests. The $20 million increase was driven by an increase in the noncontrolling ownership interests resulting from the Spectra Energy Partners public sales of additional partner units in December 2010 and June 2011, and higher earnings from Spectra Energy Partners, as a result of their acquisitions of an additional 24.5% in Gulfstream in the fourth quarter 2010 and Big Sandy in July 2011.

EBIT. The $35 million increase was primarily due to higher earnings from expansion projects, partially offset by higher operating expenses and lower contracted volumes and rates at Ozark Gas Transmission and Algonquin.

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 or the expansion of existing 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. Natural gas storage prices have recently been challenged as a result of increasing natural gas supply and narrower seasonal price spreads. NGL prices will continue to affect processing revenues that are associated with transportation services.

Our interstate pipeline operations are subject to pipeline safety regulation administered by PHMSA of the U.S. Department of Transportation. These laws and regulations require us to comply with a significant set of requirements for the design, construction, maintenance and operation of our interstate pipelines.

On January 3, 2012, the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 was signed into law. This Act amends the Pipeline Safety Act in a number of significant ways, including:

- Authorizing PHMSA to assess higher penalties for violations of its regulations, Requiring PHMSA to adopt appropriate regulations within two years requiring the use of automatic or remote-controlled shutoff valves on new or rebuilt pipeline facilities and to perform a study on the application of such technology to existing pipeline facilities in HCAs,

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Requiring operators of pipelines to verify maximum allowable operating pressure and report exceedances within five days,

Requiring PHMSA to study and report on the adequacy of soil cover requirements in HCAs, and

Requiring PHMSA to evaluate in detail whether integrity management requirements should be expanded to pipeline segments outside of HCAs (where the requirements currently apply).

In August 2011, PHMSA initiated an Advance Notice of Proposed Rulemaking announcing its consideration of substantial revisions in its regulations to increase pipeline safety. PHMSA also has issued an Advisory Bulletin which among other things, advises pipeline operators that if they are relying on design, construction, inspection, testing, or other data to determine the pressures at which their pipelines should operate, the records of that data must be traceable, verifiable and complete. These legislative and regulatory changes, when implemented, will impose additional costs on new pipeline projects as well as on existing operations. Because the extent of the new requirements and the timing of their application is still uncertain, we cannot reasonably determine the impacts that these changes will have on our operations, earnings, financial condition and cash flows at this time.

Distribution

	2012	2011	Increase (Decrease)	2010	Increase (Decrease)
		(in millions, except where noted)			
Operating revenues	$ 1,666	$ 1,831	$ (165)	$ 1,779	$ 52
Operating expenses					
Natural gas purchased	638	760	(122)	770	(10)
Operating, maintenance and other	440	441	(1)	406	35
Depreciation and amortization	213	208	5	194	14
Loss on sales of other assets and other, net	(1)		(1)		
Operating income	374	422	(48)	409	13
Other income and expenses		3	(3)		3
EBIT	$ 374	$ 425	$ (51)	$ 409	$ 16
Number of customers, thousands	1,379	1,360	19	1,344	16
Heating degree days, Fahrenheit	6,385	7,122	(737)	6,832	290
Pipeline throughput, TBtu	818	846	(28)	913	(67)
Canadian dollar exchange rate, average	1.00	0.99	0.01	1.03	(0.04)

2012 Compared to 2011

Operating Revenues. The $165 million decrease was driven by:

a $93 million decrease from lower natural gas prices passed through to customers. Prices charged to customers are adjusted quarterly based on the 12 month New York Mercantile Exchange (NYMEX) forecast,

a $70 million decrease in customer usage of natural gas primarily due to weather that was more than 10% warmer than in 2011,

a $38 million decrease as a result of an unexpected decision from the OEB in November 2012 requiring certain revenues realized from the optimization of upstream transportation contracts be refunded to customers, a $12 million decrease resulting from a weaker Canadian dollar, and

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a $6 million decrease as a result of an unfavorable decision by the OEB affecting 2010 and 2011 storage revenues, partially offset by

an $18 million increase in short-term transportation service revenues,

a $16 million increase due to lower earnings to be shared with customers, and

a $15 million increase from growth in the number of customers.

Natural Gas Purchased. The $122 million decrease was driven by:

a $93 million decrease from lower natural gas prices passed through to customers, and

a $44 million decrease due to lower volumes of natural gas sold primarily due to warmer weather, partially offset by

a $9 million increase from growth in the number of customers.

Depreciation and Amortization. The $5 million increase related to new projects placed in service, partially offset by a weaker Canadian dollar.

EBIT. The $51 million decrease was mainly a result of an unexpected decision from the OEB in November 2012 requiring certain revenues realized from the optimization of upstream transportation contracts be refunded to customers, lower customer usage due to warmer weather, higher depreciation and amortization expenses related to new projects placed in service and an unfavorable decision by the OEB affecting 2010 and 2011 storage revenues, partially offset by an increase in short-term transportation service revenues and lower earnings to be shared with customers.

2011 Compared to 2010

Operating Revenues. The $52 million increase was driven by:

a $115 million increase in customer usage of natural gas primarily due to weather that was more than 4% colder than in 2010,

a $68 million increase resulting from a stronger Canadian dollar,

a $15 million increase from growth in the number of customers, and

a $10 million increase in short-term transportation revenue due to higher exchange revenue, partially offset by

a $136 million decrease from lower natural gas prices passed through to customers,

a $12 million decrease from higher earnings to be shared with customers, and

- a $7 million decrease primarily due to lower storage prices.

Natural Gas Purchased. The $10 million decrease was driven by:

- a $136 million decrease from lower natural gas prices passed through to customers, and
- a $5 million decrease in fuel and operating costs, partially offset by
- a $102 million increase due to higher volumes of natural gas sold primarily as a result of colder weather,
- a $28 million increase resulting from a stronger Canadian dollar, and
- a $9 million increase from growth in the number of customers.

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Operating, Maintenance and Other. The $35 million increase was driven mainly by:

- a $21 million increase primarily due to higher employee benefits costs, and
- a $17 million increase resulting from a stronger Canadian dollar.

Depreciation and Amortization. The $14 million increase was driven primarily by a stronger Canadian dollar.

EBIT. The $16 million increase was mainly a result of a stronger Canadian dollar, higher customer usage of natural gas in core market, growth in the number of customers and higher short-term transportation revenue. These increases were partially offset by higher employee benefit costs, higher earnings to be shared with customers and lower storage prices.

Matters Affecting Future Distribution Results

We expect that the long-term demand for natural gas in Ontario will remain stable with continued growth in peak day demands. Growth related to the replacement of coal-fired generation will occur based upon announced projects by the Province of Ontario, and the greater role for natural gas-fired generation in balancing new sources of renewable power generation. Outside of the power market, growth driven by continued lower natural gas prices is expected to be offset in the near term by lower distribution throughput as a result of energy conservation initiatives, declining normalized use per customer and a general trend toward warmer weather.

As 2012 was the final year of Union Gas current multi-year incentive regulation framework, Union Gas filed an application with the OEB for new rates for 2013 based on traditional cost of service regulation. This rate setting process resulted in an average annual impact on a customer s total bill ranging from 0%-6% depending on their location and customer class. The draft rate order was filed with the OEB in December 2012, and approved in January 2013. Union Gas implemented the approved OEB rate order in February 2013. Union Gas expects to file its application and evidence for another incentive regulation framework with the OEB during 2013.

Natural gas storage prices have recently been challenged as a result of increasing natural gas supply and narrower seasonal price spreads. Gas supply and demand dynamics continue to change as a result of the development of new unconventional shale gas supplies. These market factors will continue to affect Union Gas unregulated storage and regulated transportation revenues in the near term.

During the past several years, the Canadian dollar has fluctuated compared to the U.S. dollar, which affected earnings to varying degrees for very short periods. Changes in the exchange rate or any other factors are difficult to predict and may affect future results.

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Western Canada Transmission & Processing

	2012	2011	Increase (Decrease)	2010	Increase (Decrease)
		(in millions, except where noted)			
Operating revenues	$ 1,546	$ 1,672	$ (126)	$ 1,345	$ 327
Operating expenses					
Natural gas and petroleum products purchased	437	432	5	290	142
Operating, maintenance and other	562	565	(3)	486	79
Depreciation and amortization	197	186	11	169	17
Loss on sales of other assets and other, net				(1)	1
Operating income	350	489	(139)	399	90
Other income and expenses	37	21	16	10	11
EBIT	$ 387	$ 510	$ (123)	$ 409	$ 101
Pipeline throughput, TBtu	662	713	(51)	627	86
Volumes processed, TBtu	665	728	(63)	664	64
Empress inlet volumes, TBtu	504	619	(115)	600	19
Canadian dollar exchange rate, average	1.00	0.99	0.01	1.03	(0.04)

2012 Compared to 2011

Operating Revenues. The $126 million decrease was driven by:

a $134 million decrease due to lower NGL sales prices associated with the Empress NGL business,

a $46 million anticipated decrease in contracted volumes in the conventional gathering and processing business due to decontracting as a result of low natural gas prices and the effect of customers shift to unconventional developments,

a $28 million decrease due to lower NGL sales volumes associated with the Empress NGL business primarily as a result of warmer weather, and

a $14 million decrease as a result of a weaker Canadian dollar, partially offset by

a $63 million increase in gathering and processing revenues due to contracted volumes from expansions associated with non-conventional supply discoveries in the Horn River and Montney areas of British Columbia,

a $16 million increase in transmission revenues primarily due to expansion,

a $10 million increase from recovery of British Columbia carbon tax and other non-income tax expense from customers, and

- a $5 million increase due primarily to higher sales volumes of residual natural gas in the Empress NGL business.

Natural Gas and Petroleum Products Purchased. The $5 million increase was driven by:

- a $14 million non-cash charge to reduce the book value of propane inventory at our Empress NGL business to estimated net realizable value, and
- an $11 million increase in natural gas purchases for extraction at the Empress extraction facility primarily due to increased volumes, partially offset by
- a $9 million decrease as a result of lower costs of natural gas purchased in the Empress NGL business caused primarily by lower extraction premiums,

- an $8 million decrease due primarily to lower volumes of make-up gas purchases in the Empress NGL business as a result of lower NGL production, and
- a $3 million decrease due to a weaker Canadian dollar.

Operating, Maintenance and Other. The $3 million decrease was driven by:

- an $18 million decrease due primarily to plant turnaround costs in 2011 that did not recur in the 2012 period,
- an $11 million decrease due primarily to lower plant fuel and electricity costs at the Empress NGL business, and
- a $5 million decrease due to a weaker Canadian dollar, partially offset by
- a $14 million increase in maintenance costs for new and existing facilities mainly due to overhauls and deactivation of projects,
- a $10 million increase in British Columbia carbon tax and other non-income tax expense, and
- an $8 million increase in project development costs due primarily to LNG pipeline project development.

Depreciation and Amortization. The $11 million increase was driven mainly by expansion projects placed in service and maintenance capital incurred, partially offset by the effect of a weaker Canadian dollar.

Other Income and Expenses. The $16 million increase was driven primarily by higher AFUDC resulting from increased capital spending on expansion projects.

EBIT. The $123 million decrease was driven by a net loss in the Empress NGL business, including an adjustment to reduce the book value of propane inventory to estimated net realizable value and lower contracted volumes in the conventional gathering and processing business, partially offset by higher gathering and processing earnings from expansions and 2011 plant turnaround costs that did not recur in 2012.

2011 Compared to 2010

Operating Revenues. The $327 million increase was driven by:

- an $81 million increase in gathering and processing revenues due primarily to contracted volumes from expansions associated with non-conventional supply discoveries in the Fort Nelson area,
- a $62 million increase as a result of a stronger Canadian dollar,
- a $60 million increase due to higher NGL sales prices associated with the Empress NGL business,
- a $51 million increase in sales volumes of residual natural gas primarily to Union Gas in the Empress NGL business,

a $33 million increase due to higher NGL sales volumes associated with the Empress NGL business resulting primarily from the effect of the scheduled plant turnaround in 2010.

a $25 million increase due to higher costs of service recovered from transportation customers, and

a $23 million increase from recovery of carbon and other non-income tax expense from customers.

Natural Gas and Petroleum Products Purchased. The $142 million increase was driven by:

a $71 million increase due primarily to increased volumes of natural gas purchases for extraction and make-up at the Empress extraction facility,

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- a $65 million increase as a result of higher prices of natural gas and other petroleum products purchased in the Empress NGL business caused primarily by higher extraction premiums, and
- a $13 million increase due to a stronger Canadian dollar.

Operating, Maintenance and Other. The $79 million increase was driven by:

- a $23 million increase in carbon and other non-income tax expense,
- a $22 million increase due to a stronger Canadian dollar,
- a $21 million increase due primarily to higher costs of service passed through to transportation customers, and
- a $7 million increase due primarily to higher maintenance costs.

Depreciation and Amortization. The $17 million increase was driven mainly by expansion projects placed in service and maintenance capital incurred, as well as a stronger Canadian dollar.

Other Income and Expenses. The $11 million increase was driven primarily by higher AFUDC resulting from higher capital spent on expansion projects.

EBIT. The $101 million increase was driven mainly by higher gathering and processing earnings from expansions, and a stronger Canadian dollar.

Matters Affecting Future Western Canada Transmission & Processing Results

Western Canada Transmission & Processing plans to continue earnings growth through capital efficient supply push projects, primarily associated with gathering and processing expansion and incremental transportation capacity to support drilling activity in northern British Columbia as well as future LNG exports. 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 18 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 NGL prices, gas flows eastbound beyond Empress and costs of acquiring natural gas and NGL extraction rights.

During the past several years, the Canadian dollar has fluctuated compared to the U.S. dollar, which affected earnings to varying degrees for very short periods. Changes in the exchange rate are difficult to predict and may affect future results.

While current drilling levels are below recent historical averages, the relatively higher productivity of unconventional wells has led to increased production supporting continued growth of Western Canada Transmission & Processing s gathering and processing business in the areas of British Columbia and Alberta where unconventional gas development is prevalent.

In certain areas of Western Canada Transmission & Processing s operations served by conventional supply, lower natural gas prices resulting from increasing North American gas production have reduced producer demand for both expansions of the British Columbia conventional gas processing plants as well as renewals of existing gas processing contracts, and could continue to do so as long as gas prices remain below historical norms.

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Field Services

	2012	2011	Increase (Decrease)	2010	Increase (Decrease)
			(in millions, except where noted)		
Equity in earnings of unconsolidated affiliates	$ 279	$ 449	$ (170)	$ 335	$ 114
EBIT	$ 279	$ 449	$ (170)	$ 335	$ 114
Natural gas gathered and processed/transported, TBtu/d (a,b)	7.1	7.0	0.1	6.9	0.1
NGL production, MBbl/d (a,c)	402	383	19	369	14
Average natural gas price per MMBtu (d,e)	$ 2.79	$ 4.04	$ (1.25)	$ 4.39	$ (0.35)
Average NGL price per gallon (f)	$ 0.82	$ 1.21	$ (0.39)	$ 0.98	$ 0.23
Average crude oil price per barrel (g)	$ 94.16	$ 95.12	$ (0.96)	$ 79.53	$ 15.59

(a) Reflects 100% of volumes.
(b) Trillion British thermal units per day.
(c) Thousand barrels per day.
(d) Average price based on NYMEX Henry Hub.
(e) Million British thermal units.
(f) Does not reflect results of commodity hedges.
(g) Average price based on NYMEX calendar month.

2012 Compared to 2011

EBIT. Lower equity earnings of $170 million were mainly the result of the following variances, each representing our 50% ownership portion of the earnings drivers at DCP Midstream:

a $272 million decrease from commodity-sensitive processing arrangements due to decreased commodity prices,

a $27 million decrease primarily attributable to higher operating costs, largely resulting from a planned increase in repairs and maintenance activities due to asset growth, and

a $24 million decrease attributable to unfavorable results from gas and NGL marketing, partially offset by

a $60 million increase due to decreased depreciation expense as a result of changes to the remaining useful lives of DCP Midstream s gathering, transmission, processing, storage and other assets during the second quarter of 2012. The key contributing factor to the change is an increase in estimated remaining economically recoverable commodity reserves, resulting from advances in extraction processes as well as improved technology used to locate commodity reserves,

a $50 million increase in gathering and processing volumes, as a result of asset growth across certain geographic regions and the absence of severe weather which caused wellhead freeze-offs which shut in gas wells and reduced recoveries in 2011,

a $19 million increase in gains associated with the issuance of partnership units by DCP Partners,

- a $10 million increase attributable to lower interest expense due to higher capitalized interest in 2012 as a result of growth, and
- a $9 million increase in earnings from DCP Partners as a result of growth and mark-to-market gains on derivative instruments used to protect distributable cash flows.

2011 Compared to 2010

EBIT. Higher equity earnings of $114 million were mainly the result of the following variances, each representing our 50% ownership portion of the earnings drivers at DCP Midstream:

- a $152 million increase from commodity-sensitive processing arrangements due to increased NGL and crude oil prices, net of decreased natural gas prices,

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a $20 million increase attributable to a decrease in interest expense due to favorable rates during 2011,

an $11 million increase attributable to decreased income tax expense related to the de-recognition of certain deferred tax assets in the 2010 period, and

a $9 million increase in earnings from DCP Partners as a result of growth and mark-to-market gains on derivative instruments used to protect distributable cash flows, partially offset by

a $64 million decrease due to higher operating expenses largely resulting from DCP Partners growth from acquisitions, increased repairs and maintenance costs and increased benefits costs, and

a $13 million decrease as a result of a gain of $30 million in 2010 associated with the issuance of partnership units by DCP Partners compared to a gain of $17 million in 2011.

Supplemental Data

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

	2012	2011	2010
		(in millions)	
Operating revenues	$ 10,171	$ 12,982	$ 10,981
Operating expenses	9,427	11,868	10,138
Operating income	744	1,114	843
Other income and expenses	34	26	34
Interest expense, net	193	213	253
Income tax expense	2	3	5
Net income	583	924	619
Net income noncontrolling interests	97	61	27
Net income attributable to members interests	$ 486	$ 863	$ 592

Matters Affecting Future Field Services Results

Drilling levels vary by geographic area, but in general, drilling remains robust in areas with a high content of liquids in the gas stream and crude oil drilling with associated gas production. In other areas, drilling continues to remain relatively modest. As a result of advances in technology, such as horizontal drilling and hydraulic fracturing in shale plays, gas production has grown significantly in relation to demand. NGL production increased during 2012 as compared to 2011 due to drilling occurring in liquids-rich areas. Gas and NGL prices are currently below levels seen in 2011 due to increasing supplies and a near record warm winter. Under DCP Midstream s contract structures, which are predominantly percent-of-proceeds contracts, DCP Midstream receives payments in-kind in the form of commodities and, as a result, typically has long natural gas and NGL positions. As such, a decrease in natural gas prices can negatively impact DCP Midstream s margin. However, any decline would be partially offset by its keep-whole contracts where gross margin is directly related to the price of NGLs and inversely related to the price of natural gas. DCP Midstream s long-term view is that as economic conditions improve, and we return to more normal weather, natural gas and NGL prices will return to levels that will support sustainable levels of natural gas drilling.

Other

	2012	2011	Increase (Decrease) (in millions)	2010	Increase (Decrease)
Operating revenues	$ 74	$ 72	$ 2	$ 58	$ 14
Operating expenses	187	170	17	95	75
Operating loss	(113)	(98)	(15)	(37)	(61)
Other income and expenses	1	(6)	7	(1)	(5)
EBIT	$ (112)	$ (104)	$ (8)	$ (38)	$ (66)

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2012 Compared to 2011

EBIT. The $8 million decrease in EBIT reflects higher corporate costs, including employee benefit costs.

2011 Compared to 2010

EBIT. The $66 million decrease in EBIT reflects a prior-year benefit of $31 million related to an early termination notice made by Westcoast Energy, Inc. (Westcoast) for capacity contracts held on the Alliance pipeline, an increase in reserves of $14 million for captive insurance for miscellaneous loss events and higher corporate costs, including employee and retiree benefit costs, partially offset by an expense in the 2010 period for resolution of a corporate legal matter.

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 the 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 assumptions that we believe are reasonable at the time of application. These estimates and judgments may change as time passes and more information becomes available. If estimates 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 operations under accounting for regulated entities. As a result, we record assets and liabilities that result from the regulated ratemaking process that may 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 or for instances where the regulator provides current rates that are intended to recover costs that are expected to be incurred in the future. 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 assessment, we believe our existing regulatory assets, which primarily relate to the future collection of deferred income tax costs for our Canadian regulated operations, 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. 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 $1,264 million as of December 31, 2012 and $1,142 million as of December 31, 2011. Total regulatory liabilities were $630 million as of December 31, 2012 and $562 million as of December 31, 2011.

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Impairment of Goodwill

We had goodwill balances of $4,513 million at December 31, 2012 and $4,420 million at December 31, 2011. The increase in goodwill in 2012 was the result of foreign currency translation. The majority of our goodwill relates to the acquisition of Westcoast in 2002, which owns significantly all 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.

As permitted under the accounting guidance on testing goodwill for impairment, we performed either a qualitative assessment or a quantitative assessment of each of our reporting units based on management s judgment. With respect to our qualitative assessments, we considered events and circumstances specific to us, such as macroeconomic conditions, industry and market considerations, cost factors and overall financial performance, when evaluating whether it was more likely than not that the fair values of our reporting units were less than their respective carrying amounts.

In connection with our quantitative assessments, we primarily used a discounted cash flow analysis to determine fair values of those reporting units. The long-term growth rates used for the reporting units that we quantitatively assessed reflect continued expansion of our assets, driven by new natural gas supplies such as shale gas in North America and increasing demand for natural gas transportation capacity on our pipeline systems primarily as a result of forecasted growth in natural gas-fired power plants. We assumed a weighted average long-term growth rate of 2.9% for our 2012 quantitative goodwill impairment analysis. Had we assumed a 100 basis point lower growth rate for each of the reporting units that we quantitatively assessed, there would have been no impairment of goodwill. We continue to monitor the effects of the global economic downturn with respect to the long-term cost of capital utilized to calculate our reporting units fair values. For our 2012 quantitative goodwill impairment analysis, we assumed weighted-average costs of capital ranging from 5.5% to 6.3% that market participants would use. Had we assumed a 100 basis point increase in the weighted-average cost of capital for each of the reporting units that we quantitatively assessed, there would have been no impairment of goodwill. For our regulated businesses in Canada, if an increase in the cost of capital occurred, we assumed that 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.

Certain commodity prices, specifically NGLs, have fluctuated in 2012 and are generally lower than prior year levels. Our Empress NGL business is significantly affected by fluctuations in commodity prices. Should NGL prices decline significantly from recent levels and further reduce earnings at the Empress NGL business, this could result in a triggering event that would warrant a testing of impairment for goodwill relating to the Empress NGL reporting unit, which could result in an impairment.

Based on the results of our annual goodwill impairment testing, no indicators of impairment were noted and the fair values of the reporting units that we quantitatively assessed at April 1, 2012 (our testing date) were substantially in excess of their respective carrying values. No triggering events occurred during the period April 1, 2012 through December 31, 2012 that would warrant re-testing for goodwill impairment. In addition, we updated our Empress NGL reporting unit s April 1, 2012 impairment test using recent operational information, financial data and December 31, 2012 commodity prices. The updated fair value of our Empress NGL reporting unit was substantially in excess of its carrying value as of December 31, 2012.

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 used in the accounting for pension and other post-retirement benefits are the expected long-term rate of return on plan assets, the assumed discount rate, and medical and prescription drug cost trend rate assumptions.

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 partially 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 2012, the assumed average return was 7.40% for the U.S. pension plan assets, 7.10% for the Canadian pension plan assets and 6.56% for the U.S. other post-retirement benefit assets. A change in the rate of return of 25 basis points for these assets would impact annual benefit expense by approximately $1 million before tax for U.S. plans, and by approximately $2 million before tax for Canadian plans. 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 4.21% for the U.S. plans and 4.30% for the Canadian plans used to calculate 2012 plan expenses represent a weighted average of the applicable rates. The applied discount rates decreased approximately 0.62% for the U.S. plans and 0.15% for the Canadian plans in 2012 compared to 2011, resulting in a significant increase in total benefit liabilities. A 25 basis-point change in the discount rates would impact annual before-tax benefit expense by approximately $1 million for U.S. plans and $4 million for Canadian plans.

See Note 24 of Notes to Consolidated Financial Statements for more information on pension and other post-retirement benefits.

LIQUIDITY AND CAPITAL RESOURCES

Known Trends and Uncertainties

As of December 31, 2012, we had negative working capital of $2,128 million. This balance includes commercial paper totaling $1,259 million and current maturities of long-term debt of $921 million. We will rely upon cash flows from operations and various financing transactions, which may include issuances of short-term and long-term debt, to fund our liquidity and capital requirements for 2013. We have access to four revolving credit facilities, with total combined capital commitments of $2,905 million, with $1,641 million available at December 31, 2012. These facilities are used principally as back-stops for commercial paper programs or for the issuance of letters of credit. At Union Gas, we primarily use commercial paper to support our short-term working capital fluctuations. At Spectra Energy Capital, LLC (Spectra Capital), Spectra Energy Partners and Westcoast, we primarily use commercial paper for temporary funding of our capital expenditures. We also utilize commercial paper, other variable-rate debt and interest rate swaps to achieve our desired mix of fixed and

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variable-rate debt. In addition, as of December 31, 2012, we also have a $1.2 billion delayed-draw term loan agreement available which allows for up to four borrowings prior to March 1, 2013. See Note 15 of Notes to Consolidated Financial Statements for a discussion of available credit facilities and Financing Cash Flows and Liquidity for a discussion of effective shelf registrations.

Our consolidated capital structure includes commercial paper, long-term debt (including current maturities), preferred stock of subsidiaries and total equity. As of December 31, 2012, our capital structure was 56% debt, 39% common equity of controlling interests and 5% noncontrolling interests and preferred stock of subsidiaries.

Cash flows from operations for our 100%-owned and majority-owned businesses are fairly stable given that approximately 90% of revenues are derived from fee-based services, of which most are regulated. 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 including DCP Midstream and Gulfstream, and the timing of cost recoveries pursuant to regulatory approvals. See Part I. Item 1A. Risk Factors for further discussion.

In particular, cash distributions from our equity affiliate DCP Midstream can fluctuate, mostly 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 mostly 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 $203 million in 2012, $395 million in 2011 and $288 million in 2010. These distributions are classified within Operating Cash Flows. 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.

In addition, cash flows from our Canadian operations are generally used to fund the ongoing Canadian businesses and future Canadian growth, in particular the significant expansion opportunities underway in western Canada. At December 31, 2012, $73 million of Cash and Cash Equivalents was held by our Canadian subsidiaries. Historically, we have reinvested a substantial portion of our Canadian operations earnings in Canada. Earnings not needed by our Canadian operations have been distributed to Spectra Energy Corp (the U.S. parent) with minimal incremental U.S. tax liability. Distributions have typically been in the range of $100 million to $300 million per year. We anticipate continued substantial reinvestment of our future Canadian earnings in Canada; however, future distributions to Spectra Energy Corp may incur incremental U.S. tax at the U.S. statutory rate without the ability to use foreign tax credits. The timing of when distributions may incur such incremental U.S. tax depends on many factors, such as the amount of future capital expansions in Canada, the tax characterization of our distributions as returns of capital or dividends, the impacts of tax planning on merger and acquisition activities and tax legislation at the time of the distributions.

As we execute on our strategic objectives around organic growth and expansion projects, expansion expenditures are expected to approximate $1.4 billion in 2013 and will continue to average approximately $1.5 billion through 2015. The timing and extent of these expenditures are likely to vary significantly from year to year, depending mostly on general economic conditions and market requirements. Given that we expect to continue to pursue expansion and earnings growth 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.

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Operating Cash Flows

Net cash provided by operating activities decreased $248 million to $1,938 million in 2012 compared to 2011. This change was driven mostly by:

- lower distributions received from DCP Midstream, and
- lower overall earnings.

Net cash provided by operating activities increased $778 million to $2,186 million in 2011 compared to 2010. This change was driven mostly by:

- lower refunds to Union Gas customers in 2011 for gas purchase costs collected in 2010 compared to refunds in 2010 for collections in 2009,
- lower net tax payments in 2011 primarily as a result of the Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act of 2010 which deferred a significant amount of tax payments to future periods, and
- higher earnings across all segments in 2011, partially offset by increased pension plan contributions in 2011.

Investing Cash Flows

Net cash flows used in investing activities was $2,674 million in 2012 compared to $2,098 million in 2011. This change was driven mostly by:

- $513 million of initial and subsequent equity investments in Sand Hills and Southern Hills in 2012,
- a $110 million increase in capital expenditures in 2012, and
- $130 million of net purchases of available-for-sale securities in 2012 compared to $190 million of net proceeds from sales and maturities in 2011, partially offset by
- a $390 million cash outlay in 2011 for the acquisition of Big Sandy.

Net cash flows used in investing activities was $2,098 million in 2011 compared to $2,101 million in 2010. This change was driven mostly by:

- a $563 million increase in capital and investment expenditures in 2011, and
- a $390 million cash outlay in 2011 for the acquisition of Big Sandy, partially offset by

a $492 million cash outlay in 2010 for the acquisition of Bobcat, and

$190 million of net proceeds from sales and maturities of available-for-sale securities in 2011 compared to $216 million of net purchases in 2010.

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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.

Capital and Investment Expenditures

	2012	2011	2010
		(in millions)	
U.S. Transmission (a)	$ 933	$ 773	$ 641
Distribution	276	292	227
Western Canada Transmission & Processing	757	776	449
Other	66	78	39
Subtotal	2,032	1,919	1,356
Investments in Sand Hills and Southern Hills	513		
Total consolidated	$ 2,545	$ 1,919	$ 1,356

(a) Excludes $30 million paid in 2012 for amounts previously withheld from the purchase price consideration of the acquisition of Bobcat, and the acquisitions of Big Sandy ($390 million) in 2011 and Bobcat ($492 million) in 2010. See Note 3 of Notes to Consolidated Financial Statements for further discussion.

Capital and investment expenditures for 2012 totaled $2,545 million and included $1,297 million for expansion projects, $735 million for maintenance and other projects and $513 million for our initial and subsequent equity investments in Sand Hills and Southern Hills. Excluding the effects of the anticipated closing of the $1.49 billion acquisition of the Express-Platte Pipeline system assets, we project 2013 capital and investment expenditures of approximately $2.2 billion, consisting of approximately $1.0 billion for U.S. Transmission, $0.4 billion for Distribution, $0.5 billion for Western Canada Transmission & Processing and $0.3 billion at Other. Total projected 2013 capital and investment expenditures include approximately $1.4 billion of expansion capital expenditures and $0.8 billion for maintenance and upgrades of existing plants, pipelines and infrastructure to serve growth.

Capital expansion projects are developed and executed using results-proven project management processes. We evaluate the strategic fit and commercial and execution risks, and continuously measure performance compared to plan. Ongoing communications between project teams and senior leadership ensure we maintain the right focus and deliver the expected results.

Expansion capital expenditures included several key projects placed into service in 2012, including:

Transmission North Project 170 MMcf/d expansion of existing western Canada transmission capacity through pipeline looping, construction of a new delivery line, a compressor upgrade at an existing station and construction of a new compressor facility, all in British Columbia.

Fort Nelson North Montney Takeaway 360 MMcf/d expansion of the Fort Nelson Mainline consisting of 24 kilometers of pipeline looping and compressor station modifications.

TEAM 2012 200 MMcf/d expansion of the Texas Eastern pipeline system consisting of new pipeline and compression construction. The project is designed to transport natural gas produced in the Marcellus Shale to markets in the U.S. Northeast.

Philadelphia Lateral 27 MMcf/d capacity increase from the take up and relay of existing pipeline. This project is designed to serve growing industrial markets in the northeast United States.

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Significant 2013 expansion projects expenditures are expected to include:

- Fort Nelson Expansion Program The new 250 MMcf/d Fort Nelson North processing facility, which is the final phase and most significant capital outlay of the program, is under construction and is scheduled to be in service during the first quarter of 2013.

- Dawson Expansion The development of a sour gas processing plant and an additional pipeline in western Canada. Phase I of 100 MMcf/d was placed into service in 2012 and Phase II for an additional 100 MMcf/d was placed into service during the first quarter of 2013.

- 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, New York and other associated facility upgrades. The project is designed to transport gas produced in the U.S. Gulf Coast, Mid-Continent, Rockies and Marcellus Shale regions into New York City. In-service is scheduled by the second half of 2013.

- Bobcat Storage The development of an additional 19.8 Bcf working gas storage cavern along with above-ground facilities in Southern Louisiana. In-service is scheduled through 2015.

- TEAM 2014 600 MMcf/d expansion of the Texas Eastern pipeline system consisting of new pipeline construction. The project is designed to transport gas produced in the Marcellus Shale to U.S. markets in the northeast, midwest and Gulf Coast. In-service is scheduled by the second half of 2014.

- North Montney Expansion 211 MMcf/d of new gathering and processing service and 159 MMcf/d of renewed gathering and processing service. The project includes various processing plant modifications, including reactivation of the existing Aitken Creek Plant. In-service is scheduled by the first half of 2014.

- Sand Hills Approximately 720 miles of NGL pipeline being constructed by DCP Midstream, with an initial capacity of 200,000 Bbls/d, transporting NGLs from the Permian Basin and Eagle Ford shale regions to NGL markets on the Gulf Coast. Phase I was completed in the fourth quarter of 2012, with initial service from the Eagle Ford shale region to Mont Belvieu. Phase II, which will provide service from the Permian Basin to the Eagle Ford shale region, is expected to be completed by the second quarter of 2013.

- Southern Hills Approximately 800 miles of NGL pipeline also being constructed by DCP Midstream, with an initial capacity of almost 150,000 Bbls/d, will connect several DCP Midstream processing plants and anticipated third-party producers and provide NGL transportation from the Mid-Continent to Mont Belvieu. In-service is scheduled by mid-2013.

Financing Cash Flows and Liquidity

Net cash provided by financing activities totaled $654 million in 2012 compared to $35 million used in financing activities in 2011. This $689 million change was driven mostly by:

- proceeds of $382 million in 2012 from the issuance of Spectra Energy common stock,

- a $299 million decrease in 2011 of Spectra Energy Partners revolving credit facility borrowings outstanding, and

- a $189 million increase in net long-term debt issuances in 2012.

Net cash used in financing activities totaled $35 million in 2011 compared to $656 million provided by financing activities in 2010. This $691 million change was driven mostly by:

- a $240 million increase in commercial paper outstanding in 2011 compared to a $669 million increase in 2010, and
- $288 million of net debt issuances in 2011, including net revolving credit facility borrowings, compared to $483 million of net issuances in 2010.

Significant Financing Activities 2012

Debt Issuances. The following long-term debt issuances were completed during 2012 as part of our overall financing plan to fund capital expenditures, to refinance maturing debt obligations and for other corporate purposes:

	Amount (in millions)	Interest Rate	Due Date
Algonquin	$ 350	3.51%	2024
Texas Eastern	500	2.80%	2022
East Tennessee	200	3.10%	2024
Westcoast	251(a)	3.12%	2022

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

Spectra Energy Common Stock Issuance. In December 2012, Spectra Energy issued 14.7 million common shares to the public. Total net proceeds to Spectra Energy were $382 million, used to fund acquisitions and capital expenditures and for other general corporate purposes.

Spectra Energy Partners Common Unit Issuance. In November 2012, Spectra Energy Partners issued 5.5 million common units to the public, representing limited partner interests, and 0.1 million general partner units to Spectra Energy. Total net proceeds to Spectra Energy Partners were $148 million (net proceeds to Spectra Energy were $145 million) and are restricted for the purpose of funding Spectra Energy Partners expenditures and acquisitions.

Significant Financing Activities 2011

Debt Issuances. The following long-term debt issuances were completed during 2011:

	Amount (in millions)	Interest Rate	Due Date
Spectra Energy Partners	$ 250	2.95%	2016
Spectra Energy Partners	250	4.60%	2021
Westcoast	151(a)	3.883%	2021
Westcoast	151(a)	4.791%	2041
Union Gas	309(a)	4.88%	2041

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

Spectra Energy Partners Common Unit Issuance. In June 2011, Spectra Energy Partners issued 7.2 million common units to the public, representing limited partner interests, and 0.1 million general partner units to Spectra Energy. Total net proceeds to Spectra Energy Partners were $218 million (net proceeds to Spectra Energy were $213 million), used to fund a portion of the acquisition of Big Sandy.

Significant Financing Activities 2010

Debt Issuances. The following long-term debt issuances were completed during 2010: