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

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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

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),

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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).

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, 2008	December 31, 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	2010
		(in millions)	
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.

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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,

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- 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 (in millions)	2010
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.

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

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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.

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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:

	Amount (in millions)	Interest Rate	Due Date
Texas Eastern	$ 300	4.125%	2020
Westcoast	249(a)	3.28%	2016
Westcoast	235(a)	4.57%	2020

Union Gas	241(a)	5.20%	2040

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

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Spectra Energy Partners Common Unit Issuance. In December 2010, Spectra Energy Partners issued 6.9 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 from the issuances was $221 million (the net proceeds to Spectra Energy was $216 million), with $209 million used to purchase qualifying investment-grade securities, $7 million used to pay the debt owed to a subsidiary of Spectra Energy and $5 million used for Spectra Energy Partners general partnership purposes. Spectra Energy Partners also borrowed $207 million of term debt using the investment-grade securities as collateral and paid off an equal amount of its outstanding revolving credit facility loan.

Available Credit Facilities and Restrictive Debt Covenants

	Expiration Date	Total Credit Facilities Capacity	Outstanding at December 31, 2012 Commercial Paper	Term Loan	Letters of Credit	Total	Available Credit Facilities Capacity
			(in millions)				
Spectra Capital							
Multi-year syndicated (a)	2016	$ 1,500	$ 514	$ n/a	$ 5	$ 519	$ 981
Delayed-draw syndicated term loan (a,b)	2015	1,200	n/a		n/a		1,200
Westcoast							
Multi-year syndicated (c)	2016	302	32	n/a		32	270
Union Gas							
Multi-year syndicated (d)	2016	403	377	n/a		377	26
Spectra Energy Partners							
Multi-year syndicated (e)	2016	700	336	n/a		336	364
Total		$ 4,105	$ 1,259	$	$ 5	$ 1,264	$ 2,841

(a) Revolving credit facility and term loan contain a covenant requiring the Spectra Energy Corp consolidated debt-to-total capitalization ratio, as defined in the agreements, to not exceed 65%. This ratio was 58% at December 31, 2012.

(b) Term loan agreement allows for up to four borrowings prior to March 1, 2013.

(c) U.S. dollar equivalent at December 31, 2012. The credit facility is 300 million Canadian dollars and contains a covenant that requires the Westcoast non-consolidated debt-to-total capitalization ratio to not exceed 75%. The ratio was 51% at December 31, 2012.

(d) U.S. dollar equivalent at December 31, 2012. The credit facility is 400 million Canadian dollars and contains a covenant that requires the Union Gas debt-to-total capitalization ratio to not exceed 75% and a provision which requires Union Gas to repay all borrowings under the facility for a period of two days during the second quarter of each year. The ratio was 68% at December 31, 2012.

(e) Credit facility contains a covenant that requires Spectra Energy Partners to maintain a ratio of total Debt-to-Adjusted Earnings Before Interest, Taxes, Depreciation and Amortization (EBITDA), as defined in the credit agreement, of 5.0 or less. As of December 31, 2012, this ratio was 3.7. Adjusted EBITDA is a non-GAAP measure. Because Adjusted EBITDA excludes some, but not all, items that affect net income and is defined differently by companies in our industry, Spectra Energy Partners definition of Adjusted EBITDA may not be comparable to similarly titled measures of other companies. Adjusted EBITDA should not be considered an alternative to net income, operating income, cash from operations or any other measure of financial performance or liquidity presented in accordance with GAAP.

The issuances of commercial paper, letters of credit and revolving borrowings reduce the amounts available under the credit facilities. As of December 31, 2012, there were no revolving borrowings outstanding.

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Our credit agreements contain various financial and other covenants, including the maintenance of certain financial ratios. Failure to meet those covenants beyond applicable grace periods could result in accelerated due dates and/or termination of the agreements. As of December 31, 2012, we were in compliance with those covenants. In addition, our credit agreements allow for the acceleration of payments or termination of the agreements due to nonpayment, or in some cases, due to the acceleration of other significant indebtedness of the borrower or some of its subsidiaries. Our debt and credit agreements do not contain provisions that trigger an acceleration of indebtedness based solely on the occurrence of a material adverse change in our financial condition or results of operations.

As noted above, the terms of our Spectra Capital credit agreement requires our consolidated debt-to-total-capitalization ratio, as defined in the agreement, to be 65% or lower. Per the terms of the agreement, collateralized debt and Spectra Energy Partners debt and capitalization are excluded in the calculation of the ratio. This ratio was 58% at December 31, 2012. Our equity, and as a result, this ratio, is sensitive to significant movements of the Canadian dollar relative to the U.S. dollar due to the significance of our Canadian operations as discussed in Quantitative and Qualitative Disclosures About Market Risk Foreign Currency Risk. Based on the strength of our total capitalization as of December 31, 2012, however, it is not likely that a material adverse effect would occur as a result of a weakened Canadian dollar.

Delayed-draw Term Loan Agreement. On December 26, 2012, Spectra Capital entered into a three-year $1.2 billion unsecured delayed-draw term loan agreement which allows for up to four borrowings prior to March 1, 2013. Proceeds from borrowings under the term loan may be used for general corporate purposes, including acquisitions and to refinance existing indebtedness. As of December 31, 2012, we had no borrowings under the term loan.

Credit Ratings

	Standard & Poor s	Moody s Investors Service	Fitch Ratings	DBRS
As of January 31, 2013				
Spectra Capital (a)	BBB	Baa2	BBB	n/a
Texas Eastern (a)	BBB+	Baa1	BBB+	n/a
Westcoast (a)	BBB+	n/a	n/a	A (low)
Union Gas (a)	BBB+	n/a	n/a	A
M&N LLC (a)	BBB-	Ba1	n/a	n/a
M&N LP (b)	A	A2/A3	n/a	A
Spectra Energy Partners (a)	BBB	Baa3	BBB	n/a

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

The above credit ratings are dependent upon, among other factors, the ability to generate sufficient cash to fund capital and investment expenditures, our results of operations, market conditions and other factors. Our credit ratings could impact our ability to raise capital in the future, impact the cost of our capital and, as a result, have an impact on our liquidity.

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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. We expect to continue our policy of paying regular cash dividends. The declaration and payment of dividends are subject to the sole discretion of our Board of Directors and will depend upon many factors, including the financial condition, earnings and capital requirements of our operating subsidiaries, covenants associated with certain debt obligations, legal requirements, regulatory constraints and other factors deemed relevant by our Board of Directors. We declared a quarterly cash dividend of $0.305 per common share on January 4, 2013 payable on March 11, 2013 to shareholders of record at the close of business on February 15, 2013.

Other Financing Matters. Spectra Energy Corp and Spectra Capital have an effective shelf registration statement on file with the SEC to register the issuance of unspecified amounts of various equity and debt securities, and Spectra Energy Partners has an effective shelf registration statement on file with the SEC to register the issuance of unspecified amounts of limited partner common units and various debt securities. In addition, as of December 31, 2012, Westcoast and Union Gas have 1.4 billion Canadian dollars (approximately $1.4 billion) available for the issuance of debt securities in the Canadian market under debt shelf prospectuses.

Off-Balance Sheet Arrangements

We enter into guarantee arrangements in the normal course of business to facilitate commercial transactions with third parties. These arrangements include financial guarantees, stand-by letters of credit, debt guarantees, surety bonds and indemnifications. See Note 19 of Notes to Consolidated Financial Statements for further discussion of guarantee arrangements.

Most of the guarantee arrangements that we enter into enhance the credit standings of certain subsidiaries, non-consolidated entities or less than 100%-owned entities, enabling them to conduct business. As such, these guarantee arrangements involve elements of performance and credit risk which are not included on our Consolidated Balance Sheets. The possibility of us having to honor our contingencies is largely dependent upon the future operations of our subsidiaries, investees and other third parties, or the occurrence of certain future events.

Issuance of these guarantee arrangements is not required for the majority of our operations. As such, if we discontinued issuing these guarantee arrangements, there would not be a material impact to our consolidated results of operations, financial position or cash flows.

We do not have any other material off-balance sheet financing entities or structures, except for normal operating lease arrangements, guarantee arrangements and financings entered into by DCP Midstream and our other equity investments. For additional information on these commitments, see Notes 18 and 19 of Notes to Consolidated Financial Statements.

Contractual Obligations

We enter into contracts that require payment of cash at certain periods based on certain specified minimum quantities and prices. The following table summarizes our contractual cash obligations for each of the periods presented. The table below excludes all amounts classified as Total Current Liabilities on the December 31, 2012 Consolidated Balance Sheet other than Current Maturities of Long-Term Debt. It is expected that the majority of Total Current Liabilities will be paid in cash in 2013.

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Contractual Obligations as of December 31, 2012

	Payments Due By Period				
	Total	2013	2014 & 2015	2016 & 2017	2018 & Beyond
			(in millions)		
Long-term debt (a)	$ 17,843	$ 1,569	$ 2,626	$ 2,308	$ 11,340
Operating leases (b)	377	60	102	64	151
Purchase Obligations: (c)					
Firm capacity payments (d)	681	301	268	42	70
Energy commodity contracts (e)	330	289	32	9	
Other purchase obligations (f)	329	122	126	50	31
Other long-term liabilities on the Consolidated Balance Sheet (g)	117	117			
Total contractual cash obligations	$ 19,677	$ 2,458	$ 3,154	$ 2,473	$ 11,592

(a) See Note 15 of Notes to Consolidated Financial Statements. Amounts include estimated scheduled interest payments over the life of the associated debt.
(b) See Note 19.
(c) Purchase obligations reflected in the Consolidated Balance Sheets have been excluded from the above table.
(d) Includes firm capacity payments that provide us with uninterrupted firm access to natural gas transportation and storage.
(e) Includes contractual obligations to purchase physical quantities of NGLs and natural gas. Amounts include certain hedges as defined by applicable accounting standards. For contracts where the price paid is based on an index, the amount is based on forward market prices at December 31, 2012.
(f) Includes contracts for software and consulting or advisory services. Amounts also include contractual obligations for engineering, procurement and construction costs for pipeline projects. Amounts exclude certain open purchase orders for services that are provided on demand, where the timing of the purchase cannot be determined.
(g) Includes estimated 2013 retirement plan contributions and estimated 2013 payments related to uncertain tax positions, including interest (see Notes 6 and 24). We are unable to reasonably estimate the timing of uncertain tax positions and interest payments in years beyond 2013 due to uncertainties in the timing of cash settlements with taxing authorities and cannot estimate retirement plan contributions beyond 2013 due primarily to uncertainties about market performance of plan assets. Excludes cash obligations for asset retirement activities (see Note 14) because the amount of cash flows to be paid to settle the asset retirement obligations is not known with certainty as we may use internal or external resources to perform retirement activities. Amounts also exclude reserves for litigation and environmental remediation (see Note 19) and regulatory liabilities (see Note 5) because we are uncertain as to the amount and/or timing of when cash payments will be required. Amounts also exclude deferred income taxes and investment tax credits on the Consolidated Balance Sheets since cash payments for income taxes are determined primarily by taxable income for each discrete fiscal year.

Quantitative and Qualitative Disclosures About Market Risk

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

Commodity Price Risk

We are exposed to the impact of market fluctuations in the prices of NGLs and natural gas purchased as a result of our investment in DCP Midstream, and the ownership of the NGL marketing operations in western

Canada and the processing plants associated with our U.S. pipeline assets. Price risk represents the potential risk of loss from adverse changes in the market price of these energy commodities. Our exposure to commodity price risk is influenced by a number of factors, including contract size, length, market liquidity, location and unique or specific contract terms.

We employ policies and procedures to manage Spectra Energy s risks associated with Empress commodity price fluctuations, which may include the use of forward physical transactions as well as commodity derivatives. There were no significant commodity hedge transactions by Spectra Energy during 2012, 2011 or 2010.

DCP Midstream manages their direct exposure to these market prices separate from Spectra Energy, and utilizes various risk management strategies, including the use of commodity derivatives.

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, natural gas and oil primarily in our Field Services segment. Based on a sensitivity analysis as of December 31, 2012 and 2011, a 10¢ per-gallon move in NGL prices would affect our annual pre-tax earnings by approximately $65 million in both 2013 and 2012 for Field Services. For the same periods, a 50¢ per-MMBtu move in natural gas prices would affect our annual pre-tax earnings by approximately $18 million in 2013 and $15 million in 2012, and a $10 per-barrel move in oil prices would affect our annual pre-tax earnings by approximately $25 million in both 2013 and 2012.

With respect to the Empress assets in Western Canada Transmission & Processing, a 10¢ per-gallon move in NGL prices, primarily propane prices, would affect our annual pre-tax earnings by approximately $22 million in 2013, as compared with approximately $25 million in 2012. For the same periods, a 50¢ per-MMBtu move in natural gas prices would affect our annual pre-tax earnings by approximately $13 million in 2013 and $14 million in 2012.

These hypothetical calculations consider estimated production levels, but do not consider other potential effects that might result from such changes in commodity prices. The actual effect of commodity price changes on our earnings could be significantly different than these estimates.

See also Notes 1 and 18 of Notes to Consolidated Financial Statements.

Credit Risk

Credit risk represents the loss that we would incur if a counterparty fails to perform under its contractual obligations. Our principal customers for natural gas transportation, storage, and gathering and processing services are industrial end-users, marketers, exploration and production companies, LDCs and utilities located throughout the United States and Canada. We have concentrations of receivables from natural gas utilities and their affiliates, industrial customers and marketers throughout these regions, as well as retail distribution customers in Canada. These concentrations of customers may affect our overall credit risk in that risk factors can negatively affect the credit quality of the entire sector. Credit risk associated with gas distribution services are primarily affected by general economic conditions in the service territory.

Where exposed to credit risk, we analyze the customers financial condition prior to entering into an agreement, establish credit limits and monitor the appropriateness of those limits on an ongoing basis. We also obtain parental guarantees, cash deposits or letters of credit from customers to provide credit support, where appropriate, based on our financial analysis of the customer and the regulatory or contractual terms and conditions applicable to each contract. 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

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would be impacted by deteriorating conditions in the economy, including possible declines in our customers creditworthiness. As a result of future capital projects for which natural gas producers may be the primary customer, the percentage of our customers who are rated investment-grade may decline.

We manage cash and restricted cash positions to maximize value while assuring appropriate amounts of cash are available, as required. We invest our available cash in high-quality money market securities. Such money market securities are designed for safety of principal and liquidity, and accordingly, do not include equity-based securities.

We had no net exposure to any customer that represented greater than 10% of the gross fair value of trade accounts receivable at December 31, 2012.

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

Interest Rate Risk

We are exposed to risk resulting from changes in interest rates as a result of our issuance of variable and fixed-rate debt and commercial paper. We manage our interest rate exposure by limiting our variable-rate exposures to percentages of total debt and by monitoring the effects of market changes in interest rates. We also enter into financial derivative instruments, including, but not limited to, interest rate swaps and rate lock agreements to manage and mitigate interest rate risk exposure. See also Notes 1, 15 and 18 of Notes to Consolidated Financial Statements.

As of December 31, 2012, we had interest rate hedges in place for various purposes. We are party to pay floating receive fixed interest rate swaps with a total notional amount of $2,102 million to hedge against changes in the fair value of our fixed-rate debt that arise as a result of changes in market interest rates. These swaps also allow us to transform a portion of the underlying interest payments related to our long-term fixed-rate debt securities into variable-rate interest payments in order to achieve our desired mix of fixed and variable-rate debt.

Based on a sensitivity analysis as of December 31, 2012, it was estimated that if short-term interest rates average 100 basis points higher (lower) in 2013 than in 2012, interest expense, net of offsetting impacts in interest income, would increase (decrease) by $29 million. Comparatively, based on a sensitivity analysis as of December 31, 2011, had short-term interest rates averaged 100 basis points higher (lower) in 2012 than in 2011, it was estimated that interest expense, net of offsetting interest income, would have fluctuated by approximately $24 million. These amounts were estimated by considering the effect of the hypothetical interest rates on variable-rate debt outstanding, adjusted for interest rate hedges, investments, and cash and cash equivalents outstanding as of December 31, 2012 and 2011.

Equity Price Risk

Our cost of providing non-contributory defined benefit retirement and postretirement benefit plans are dependent upon, among other things, rates of return on plan assets. These plan assets expose us to price fluctuations in equity markets. In addition, our captive insurance companies maintain various investments to fund certain business risks and losses. Those investments may, from time to time, include investments in equity securities. Volatility of equity markets, particularly declines, will not only impact our cost of providing retirement and postretirement benefits, but will also impact the funding level requirements of those benefits.

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

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Foreign Currency Risk

We are exposed to foreign currency risk from our Canadian operations. To mitigate risks associated with foreign currency fluctuations, contracts may be denominated in or indexed to the U.S. dollar and/or local inflation rates, or investments may be naturally hedged through debt denominated or issued in the foreign currency.

To monitor our currency exchange rate risks, we use sensitivity analysis, which measures the effect of devaluation of the Canadian dollar. An average 10% devaluation in the Canadian dollar exchange rate during 2012 would have resulted in an estimated net loss on the translation of local currency earnings of approximately $41 million on our Consolidated Statement of Operation. 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 AOCI. At December 31, 2012, one U.S. dollar translated into 0.99 Canadian dollars.

As discussed earlier, we maintain credit facilities that typically include financial covenants which limit the amount of debt that can be outstanding as a percentage of total capital for Spectra Energy or of a specific subsidiary. Failure to maintain these covenants could preclude us from issuing commercial paper or letters of credit or borrowing under our revolving credit facilities and could require other affiliates to immediately pay down any outstanding drawn amounts under other revolving credit agreements, which could adversely affect cash flows or restrict business. As a result of the impact of foreign currency fluctuations on our consolidated equity, these fluctuations have a direct impact on our ability to maintain certain of these financial covenants.

OTHER ISSUES

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

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 ratified by the United States. United Nations-sponsored international negotiations were held in Doha, Qatar in December 2012 with the intent of laying the groundwork for a new global agreement on climate action to come into effect by 2020. An agreement was reached to amend the Kyoto Protocol extending it to 2020 when a potential new agreement could take effect.

In 2011, the Canadian government withdrew from the Kyoto Protocol. In 2008, the Canadian government outlined a regulatory framework mandating GHG reductions from large final emitters. Regulatory design details from the Canadian government remain forthcoming. We expect a number of our assets and operations in Canada will be affected by future federal climate change regulations. However, the materiality of any potential compliance costs is unknown at this time as the final form of the regulation and compliance options have yet to be determined by policymakers.

The province of British Columbia enacted a carbon tax, effective July 1, 2008. The tax applies to the purchase or use of fossil fuels, including natural gas. This tax is being recovered from customers through service tolls. British Columbia has also introduced legislation establishing targets for the purpose of reducing GHG emissions to at least 33% less than 2007 levels by 2020 and to at least 80% less than 2007 levels by 2050. In 2008, the province established additional interim GHG reduction targets of 6% below 2007 levels by 2012 and 18% below by 2016. British Columbia has also issued consultation papers regarding potential development of a

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cap and trade program; however, no decision has been made on whether to implement the program. The materiality of any potential compliance costs is unknown at this time as the final form of additional regulations and compliance options has yet to be determined by policymakers.

In 2007, the province of Alberta adopted legislation which requires existing large emitters (facilities releasing 100,000 metric tons or more of GHG emissions annually) to reduce their annual emissions intensity by 12% beginning July 1, 2007. In 2012, one of our facilities was subject to this regulation. The regulation has not had a material impact on our consolidated results of operations, financial position or cash flows.

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

The United States has not ratified the Kyoto Protocol, nor has the federal government adopted a mandatory GHG emissions reduction requirement for our sector. The EPA has issued a final Mandatory Greenhouse Gas Reporting rule in 2009 that required annual reporting of GHG emissions data from certain of our U.S. operations beginning in 2010. In 2010, the EPA released additional requirements for natural gas system reporting that have expanded the reporting requirements for GHG emissions starting in 2011. These reporting requirements have not had and are not anticipated to have a material impact on our consolidated results of operations, financial position or cash flows. In 2010, the EPA issued the Prevention of Significant Deterioration (PSD) and Title V Greenhouse Gas Tailoring Rule (Tailoring Rule). This regulation establishes that, beginning in January 2011, the construction of new or the modification of existing major sources of GHG emissions would become subject to the PSD air permitting program (and later, the Title V permitting program). This regulation also significantly increased the emission thresholds that would determine what facilities will become subject 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.

In addition, several legislative proposals that would impose GHG emissions constraints have been considered by the U.S. Congress. To date, no such legislation has been enacted into law. A number of states in the United States are establishing or considering state or regional programs that would mandate reductions in GHG emissions. These regional programs include the Regional Greenhouse Gas Initiative which applies only to power producers in select northeastern states, the Western Climate Initiative which includes California and the provinces of British Columbia, Manitoba, Ontario and Quebec, and the Midwestern Greenhouse Gas Reduction Accord which includes six midwestern states and one Canadian province. We expect some of our assets and operations could be affected either directly or indirectly by state or regional programs. However, as the key details of future GHG restrictions and compliance mechanisms remain undefined, the likely future effects on our business are highly uncertain.

Due to the speculative outlook regarding any U.S. federal and state policies and the uncertainty of the Canadian federal and provincial policies, we cannot estimate the potential effect of proposed GHG policies on our future consolidated results of operations, financial position or cash flows. However, such legislation or regulation could materially increase our operating costs, require material capital expenditures or create additional permitting, which could delay proposed construction projects. We continue to monitor the development of greenhouse gas regulatory policies in both countries.

Other. For additional information on other issues, see Notes 5 and 19 of Notes to Consolidated Financial Statements.

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New Accounting Pronouncements

There were no significant accounting pronouncements adopted during 2012, 2011 or 2010 that had a material impact on our consolidated results of operations, financial position or cash flows.

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

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

Item 8. Financial Statements and Supplementary Data.

Management s Annual Report on Internal Control over Financial Reporting

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

Our management, including our Chief Executive Officer and Chief Financial Officer, has conducted an evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2012 based on the framework in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on that evaluation, management concluded that our internal control over financial reporting was effective at the reasonable assurance level as of December 31, 2012.

Deloitte & Touche LLP, our independent registered public accounting firm, has audited and issued a report on the effectiveness of our internal control over financial reporting. Their report is included herein.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheets of Spectra Energy Corp and subsidiaries (the Company) as of December 31, 2012 and 2011, and the related consolidated statements of operations, comprehensive income, cash flows, and equity for each of the three years in the period ended December 31, 2012. Our audits also included the financial statement schedule listed in the index at Item 15. We also have audited the Company s internal control over financial reporting as of December 31, 2012, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company s management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management s Annual Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on these financial statements and financial statement schedule and an opinion on the Company s internal control over financial reporting based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company s internal control over financial reporting is a process designed by, or under the supervision of, the company s principal executive and principal financial officers, or persons performing similar functions, and effected by the company s board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company s assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

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In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Spectra Energy Corp and subsidiaries as of December 31, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2012, based on the criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas

February 22, 2013

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SPECTRA ENERGY CORP

CONSOLIDATED STATEMENTS OF OPERATIONS

(In millions, except per-share amounts)

	Years Ended December 31, 2012	2011	2010
Operating Revenues			
Transportation, storage and processing of natural gas	$ 3,149	$ 3,139	$ 2,870
Distribution of natural gas	1,366	1,481	1,450
Sales of natural gas liquids	401	564	459
Other	159	167	166
Total operating revenues	5,075	5,351	4,945
Operating Expenses			
Natural gas and petroleum products purchased	1,037	1,142	1,056
Operating, maintenance and other	1,382	1,415	1,278
Depreciation and amortization	746	709	650
Property and other taxes	337	330	297
Total 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			
Equity in earnings of unconsolidated affiliates	382	549	430
Other income and expenses, net	83	57	32
Total 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
Common Stock Data			
Weighted-average shares outstanding			
Basic	653	650	648
Diluted	656	653	650
Earnings per share from continuing operations			

Basic	$ 1.44	$ 1.78	$ 1.61
Diluted	$ 1.43	$ 1.77	$ 1.60
Earnings per share			
Basic	$ 1.44	$ 1.82	$ 1.62
Diluted	$ 1.43	$ 1.81	$ 1.61
Dividends per share	$ 1.145	$ 1.06	$ 1.00

See Notes to Consolidated Financial Statements.

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SPECTRA ENERGY CORP

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(In millions)

	Years Ended December 31,		
	2012	**2011**	**2010**
Net Income	$ 1,047	$ 1,282	$ 1,129
Other comprehensive income (loss):			
Foreign currency translation adjustments	215	(181)	344
Unrealized mark-to-market net gain (loss) on hedges	6	(3)	(28)
Reclassification of cash flow hedges into earnings	9	9	1
Pension and benefits impact	9	(159)	(7)
Other		14	
Total other comprehensive income (loss)	239	(320)	310
Total Comprehensive Income, net of tax	1,286	962	1,439
Less: Comprehensive Income Noncontrolling Interests	110	100	96
Comprehensive Income Controlling Interests	$ 1,176	$ 862	$ 1,343

See Notes to Consolidated Financial Statements.

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SPECTRA ENERGY CORP

CONSOLIDATED BALANCE SHEETS

(In millions)

	December 31, 2012	December 31, 2011
ASSETS		
Current Assets		
Cash and cash equivalents	$ 94	$ 174
Receivables (net of allowance for doubtful accounts of $13 and $14 at December 31, 2012 and 2011, respectively)	970	962
Inventory	309	393
Other	290	235
Total current assets	1,663	1,764
Investments and Other Assets		
Investments in and loans to unconsolidated affiliates	2,692	2,064
Goodwill	4,513	4,420
Other	572	530
Total investments and other assets	7,777	7,014
Property, Plant and Equipment		
Cost	26,257	23,932
Less accumulated depreciation and amortization	6,352	5,674
Net property, plant and equipment	19,905	18,258
Regulatory Assets and Deferred Debits	1,242	1,102
Total Assets	$ 30,587	$ 28,138

See Notes to Consolidated Financial Statements.

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SPECTRA ENERGY CORP

CONSOLIDATED BALANCE SHEETS

(In millions, except per-share amounts)

	December 31, 2012	December 31, 2011
LIABILITIES AND EQUITY		
Current Liabilities		
Accounts payable	$ 464	$ 498
Commercial paper	1,259	1,052
Taxes accrued	67	82
Interest accrued	185	178
Current maturities of long-term debt	921	525
Other	895	766
Total current liabilities	3,791	3,101
Long-term Debt	10,653	10,146
Deferred Credits and Other Liabilities		
Deferred income taxes	4,358	3,940
Regulatory and other	1,684	1,797
Total deferred credits and other liabilities	6,042	5,737
Commitments and Contingencies		
Preferred Stock of Subsidiaries	258	258
Equity		
Preferred stock, $0.001 par, 22 million shares authorized, no shares outstanding		
Common stock, $0.001 par, 1 billion shares authorized, 668 million and 651 million shares outstanding at December 31, 2012 and 2011, respectively	1	1
Additional paid-in capital	5,297	4,814
Retained earnings	2,165	1,977
Accumulated other comprehensive income	1,509	1,273
Total controlling interests	8,972	8,065
Noncontrolling interests	871	831
Total equity	9,843	8,896
Total Liabilities and Equity	$ 30,587	$ 28,138

See Notes to Consolidated Financial Statements.

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SPECTRA ENERGY CORP

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In millions)

	Years Ended December 31, 2012	2011	2010
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$ 1,047	$ 1,282	$ 1,129
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	760	725	664
Deferred income tax expense	210	373	205
Equity in earnings of unconsolidated affiliates	(382)	(549)	(430)
Distributions received from unconsolidated affiliates	307	499	391
Decrease (increase) in			
Receivables	69	(15)	(50)
Inventory	80	(99)	14
Other current assets	1	(20)	4
Increase (decrease) in			
Accounts payable	(51)	90	(67)
Taxes accrued	14	33	(141)
Other current liabilities	43	12	(184)
Other, assets	(74)	(42)	(49)
Other, liabilities	(86)	(103)	(78)
Net cash provided by operating activities	1,938	2,186	1,408
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures	(2,025)	(1,915)	(1,346)
Investments in and loans to unconsolidated affiliates	(520)	(4)	(10)
Acquisitions, net of cash acquired	(30)	(390)	(492)
Purchases of held-to-maturity securities	(2,671)	(1,695)	(1,117)
Proceeds from sales and maturities of held-to-maturity securities	2,578	1,709	1,068
Purchases of available-for-sale securities	(644)	(953)	(254)
Proceeds from sales and maturities of available-for-sale securities	514	1,143	38
Distributions received from unconsolidated affiliates	17	17	17
Other changes in restricted funds	93	(64)	
Other	14	54	(5)
Net cash used in investing activities	(2,674)	(2,098)	(2,101)
CASH FLOWS FROM FINANCING ACTIVITIES			
Proceeds from the issuance of long-term debt	1,301	1,118	1,232
Payments for the redemption of long-term debt	(525)	(531)	(807)
Net increase in commercial paper	199	240	669
Net increase (decrease) in revolving credit facilities borrowings		(299)	58
Distributions to noncontrolling interests	(120)	(101)	(73)
Proceeds from the issuance of Spectra Energy common stock	382		
Proceeds from the issuance of Spectra Energy Partners, LP common units	145	213	216
Dividends paid on common stock	(753)	(694)	(650)
Other	25	19	11
Net cash provided by (used in) financing activities	654	(35)	656

Effect of exchange rate changes on cash		2		(9)		1
Net increase (decrease) in cash and cash equivalents		(80)		44		(36)
Cash and cash equivalents at beginning of period		174		130		166
Cash and cash equivalents at end of period	$	94	$	174	$	130
Supplemental Disclosures						
Cash paid for interest, net of amount capitalized	$	601	$	598	$	615
Cash paid for income taxes, net of refunds received		130		76		312
Property, plant and equipment non-cash accruals		147		137		58

See Notes to Consolidated Financial Statements.

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SPECTRA ENERGY CORP

CONSOLIDATED STATEMENTS OF EQUITY

(In millions)

	Common Stock	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income: Foreign Currency Translation Adjustments	Accumulated Other Comprehensive Income: Other	Noncontrolling Interests	Total
December 31, 2009	$ 1	$ 4,645	$ 1,088	$ 1,682	$ (375)	$ 540	$ 7,581
Net income			1,049			80	1,129
Other comprehensive income (loss)				328	(34)	16	310
Dividends on common stock			(650)				(650)
Stock-based compensation		36					36
Distributions to noncontrolling interests						(73)	(73)
Spectra Energy Partners, LP common units issued		50				140	190
Transfer of interest in Gulfstream Natural Gas System, LLC to Spectra Energy Partners, LP		19				(29)	(10)
Other, net		(24)			(6)	4	(26)
December 31, 2010	1	4,726	1,487	2,010	(415)	678	8,487
Net income			1,184			98	1,282
Other comprehensive income				(178)	(144)	2	(320)
Dividends on common stock			(694)				(694)
Stock-based compensation		18					18
Distributions to noncontrolling interests						(101)	(101)
Spectra Energy common stock issued		32					32
Spectra Energy Partners, LP common units issued		38				154	192
December 31, 2011	1	4,814	1,977	1,832	(559)	831	8,896
Net income			940			107	1,047
Other comprehensive income				212	24	3	239
Dividends on common stock			(752)				(752)
Stock-based compensation		24					24
Distributions to noncontrolling interests						(120)	(120)
Spectra Energy common stock issued		399					399
Spectra Energy Partners, LP common units issued		26				108	134
Transfer of interest in Maritimes & Northeast Pipeline, L.L.C. to Spectra Energy Partners, LP		34				(54)	(20)
Other, net						(4)	(4)
December 31, 2012	$ 1	$ 5,297	$ 2,165	$ 2,044	$ (535)	$ 871	$ 9,843

See Notes to Consolidated Financial Statements.

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SPECTRA ENERGY CORP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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1. Summary of Operations and Significant Accounting Policies

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

Nature of Operations. Spectra Energy Corp, through its subsidiaries and equity affiliates, owns and operates a large and diversified portfolio of complementary natural gas-related energy assets, currently operating in three key areas of the natural gas industry: gathering and processing, transmission and storage, and distribution. We provide transportation and storage of natural gas to customers in various regions of the northeastern and southeastern United States, the Maritime Provinces in Canada and the Pacific Northwest in the United States and Canada, and in the province of Ontario, Canada. We also provide natural gas sales and distribution services to retail customers in Ontario, and natural gas gathering and processing services to customers in western Canada. In addition, we own a 50% interest in DCP Midstream, LLC (DCP Midstream), 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).

Basis of Presentation. The accompanying Consolidated Financial Statements include our accounts and the accounts of our majority-owned subsidiaries, after eliminating intercompany transactions and balances.

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Use of Estimates. To conform with generally accepted accounting principles (GAAP) in the United States, we make estimates and assumptions that affect the amounts reported in the Consolidated Financial Statements and Notes to Consolidated Financial Statements. Although these estimates are based on our best available knowledge at the time, actual results could differ.

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

Cost-Based Regulation. The economic effects of regulation can result in a regulated company recording assets for costs that have been or are expected to be approved for recovery from customers or recording liabilities for amounts that are expected to be returned to customers or for instances where the regulator provides current rates that are intended to recover costs that are expected to be incurred in the future. Accordingly, we record assets and liabilities that result from the regulated ratemaking process that may not be recorded under GAAP for non-regulated entities. We continually assess whether regulatory assets are probable of future recovery by considering factors such as applicable regulatory changes and recent rate orders to other regulated entities. Based on this assessment, we believe our existing regulatory assets are probable of recovery. These regulatory assets and liabilities are mostly classified in the Consolidated Balance Sheets as Regulatory Assets and Deferred Debits, and Deferred Credits and Other Liabilities   Regulatory and Other. We evaluate our regulated assets, and consider factors such as regulatory changes and the effect of competition. If cost-based regulation ends or competition increases, we may have to reduce our asset balances to reflect a market basis less than cost and write-off the associated regulatory assets and liabilities. See Note 5 for further discussion.

Foreign Currency Translation. The Canadian dollar has been determined to be the functional currency of our Canadian operations based on an assessment of the economic circumstances of those operations. Assets and liabilities of our Canadian operations are translated into U.S. dollars at current exchange rates. Translation adjustments resulting from fluctuations in exchange rates are included as a separate component of Accumulated Other Comprehensive Income (AOCI) on the Consolidated Statements of Comprehensive Income. Revenue and expense accounts of these operations are translated at average monthly exchange rates prevailing during the periods. Gains and losses arising from transactions denominated in currencies other than the functional currency are included in the results of operations of the period in which they occur. Foreign currency transaction losses totaled $3 million in 2012, $6 million in 2011 and $9 million in 2010, and are included in Other Income and Expenses, Net on the Consolidated Statements of Operations. Deferred U.S. federal taxes have not been provided on our Canadian translation gains and losses since we expect earnings of those operations to be indefinitely invested.

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. There were no customers accounting for 10% or more of consolidated revenues during 2012, 2011 or 2010.

Stock-Based Compensation. For employee awards, equity-classified and liability-classified stock-based compensation cost is measured at the grant date based on the fair value of the award. Liability-classified stock-based compensation cost is remeasured at each reporting period until settlement. The compensation cost is recognized as expense over the requisite service period, which generally begins on the date the award is granted through the earlier of the date the award vests or the date the employee becomes retirement-eligible. Awards, including stock options, granted to employees that are retirement-eligible are deemed to have vested immediately upon issuance, and therefore, compensation cost for those awards is recognized on the date such awards are granted. See Note 23 for further discussion.

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Allowance for Funds Used During Construction (AFUDC). AFUDC, which represents the estimated debt and equity costs of capital funds necessary to finance the construction of certain new regulated facilities, consists of two components, an equity component and an interest expense component. The equity component is a non-cash item. AFUDC is capitalized as a component of Property, Plant and Equipment cost, with offsetting credits to the Consolidated Statements of Operations through Other Income and Expenses, Net for the equity component and Interest Expense for the interest expense component. After construction is completed, we are permitted to recover these costs through inclusion in the rate base and in the depreciation provision. The total amount of AFUDC included in the Consolidated Statements of Operations was $131 million in 2012 (an equity component of $85 million and an interest expense component of $46 million), $82 million in 2011 (an equity component of $52 million and an interest expense component of $30 million) and $52 million in 2010 (an equity component of $37 million and an interest expense component of $15 million).

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

Financial statement effects on tax positions are recognized in the period in which it is more likely than not that the position will be sustained upon examination, the position is effectively settled or when the statute of limitations to challenge the position has expired. Interest and penalties related to unrecognized tax benefits are recorded as interest expense and other expense, respectively.

Cash and Cash Equivalents. Highly liquid investments with original maturities of three months or less at the date of acquisition, except for the investments that were pledged as collateral against long-term debt as discussed in Note 15 and any investments that are considered restricted funds, are considered cash equivalents.

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

Natural Gas Imbalances. The Consolidated Balance Sheets include in-kind balances as a result of differences in gas volumes received and delivered for customers. Since settlement of certain imbalances is in-kind, changes in their balances do not have an effect on our Consolidated Statements of Cash Flows. Receivables includes $336 million and $245 million as of December 31, 2012 and December 31, 2011, respectively, and Other Current Liabilities includes $332 million and $245 million as of December 31, 2012 and December 31, 2011, respectively, related to all gas imbalances. Most natural gas volumes owed to or by us are valued at natural gas market index prices as of the balance sheet dates.

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

Cash Flow and Fair Value Hedges. Qualifying energy commodity and other derivatives may be designated as either a hedge of a forecasted transaction (cash flow hedge) or a hedge of a recognized asset, liability or firm commitment (fair value hedge). For all hedge contracts, we prepare documentation of the hedge in accordance with accounting standards and assess whether the hedge contract is highly effective using regression analysis, both at inception and on a quarterly basis, in offsetting changes in cash flows or fair values of hedged items. We document hedging activity by instrument type (futures or swaps) and risk management strategy (commodity price risk or interest rate risk).

Changes in the fair value of a derivative designated and qualified as a cash flow hedge, to the extent effective, are included in the Consolidated Statements of Comprehensive Income as AOCI until earnings are affected by the hedged item. We discontinue hedge accounting prospectively when we have determined that a derivative no longer qualifies as an effective hedge or when it is no longer probable that the hedged forecasted transaction will occur. When hedge accounting is discontinued because the derivative no longer qualifies as an effective hedge, the derivative is subject to the mark-to-market model of accounting prospectively. Gains and losses related to discontinued hedges that were previously accumulated in AOCI remain in AOCI until the underlying transaction is reflected in earnings, unless it is probable that the hedged forecasted transaction will not occur at which time associated deferred amounts in AOCI are immediately recognized in current earnings.

For derivatives designated as fair value hedges, we recognize the gain or loss on the derivative instrument, as well as the offsetting gain or loss on the hedged item in earnings, to the extent effective, in the current period. In the event the hedge is not effective, there is no offsetting gain or loss recognized in earnings for the hedged item. All derivatives designated and accounted for as hedges are classified in the same category as the item being hedged in the Consolidated Statements of Cash Flows. All components of each derivative gain or loss are included in the assessment of hedge effectiveness.

Investments. We may actively invest a portion of our available cash and restricted funds balances in various financial instruments, including taxable or tax-exempt debt securities. In addition, we invest in short- term money market securities, some of which are restricted due to debt collateral or insurance requirements. Investments in available-for-sale (AFS) securities are carried at fair value and investments in held-to-maturity (HTM) securities are carried at cost. Investments in money market securities are also accounted for at fair value. Realized gains and losses, and dividend and interest income related to these securities, including any amortization of discounts or premiums arising at acquisition, are included in earnings. The cost of securities sold is determined using the specific identification method. Purchases and sales of AFS and HTM securities are presented on a gross basis within Cash Flows From Investing Activities in the accompanying Consolidated Statements of Cash Flows.

Goodwill. We perform our goodwill impairment test annually and evaluate goodwill when events or changes in circumstances indicate that its carrying value may not be recoverable. No impairments of goodwill were recorded in 2012, 2011 or 2010. See Note 12 for further discussion.

We perform our annual review for goodwill impairment at the reporting unit level, which is identified by assessing whether the components of our operating segments constitute businesses for which discrete financial information is available, whether segment management regularly reviews the operating results of those components and whether the economic and regulatory characteristics are similar. We determined that our reporting units are equivalent to our reportable segments, except for the reporting units of our Western Canada Transmission & Processing reportable segment, which are one level below.

As permitted under 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 the fair values of those reporting units. Key assumptions in the determination of fair value included the use of an appropriate discount rate and estimated future cash flows. In estimating cash flows, we incorporated

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expected long-term growth rates in key markets served by our operations, regulatory stability, the ability to renew contracts, and commodity prices and foreign currency exchange rates where appropriate, as well as other factors that affect our reporting units revenue, expense and capital expenditure projections. If the carrying amount of the reporting unit exceeds its fair value, a comparison of the fair value and carrying value of the goodwill of that reporting unit needs to be performed. If the carrying value of the goodwill of a reporting unit exceeds the implied fair value of that goodwill, an impairment loss is recognized in an amount equal to the excess. Additional impairment tests are performed between the annual reviews if events or changes in circumstances make it more likely than not that the fair value of a reporting unit is below its carrying amount.

Property, Plant and Equipment. Property, plant and equipment is stated at historical cost less accumulated depreciation. We capitalize all construction-related direct labor and material costs, as well as indirect construction costs. Indirect costs include general engineering, taxes and the cost of funds used during construction. The costs of renewals and betterments that extend the useful life or increase the expected output of property, plant and equipment are also capitalized. The costs of repairs, replacements and major maintenance projects that do not extend the useful life or increase the expected output of property, plant and equipment are expensed as incurred. Depreciation is generally computed over the asset s estimated useful life using the straight-line method.

When we retire regulated property, plant and equipment, we charge the original cost plus the cost of retirement, less salvage value, to accumulated depreciation and amortization. When we sell entire regulated operating units or retire non-regulated properties, the cost is removed from the property account and the related accumulated depreciation and amortization accounts are reduced. Any gain or loss is recorded in earnings, unless otherwise required by the applicable regulatory body.

Preliminary Project Costs. Project development costs, including expenditures for preliminary surveys, plans, investigations, environmental studies, regulatory applications and other costs incurred for the purpose of determining the feasibility of capital expansion projects, are capitalized for rate-regulated enterprises when it is determined that recovery of such costs through regulated revenues of the completed project is probable. Any inception-to-date costs of the project that were initially expensed are reversed and capitalized as Property, Plant and Equipment.

Long-Lived Asset Impairments. We evaluate whether long-lived assets, excluding goodwill, have been impaired when circumstances indicate the carrying value of those assets may not be recoverable. For such long-lived assets, an impairment exists when its carrying value exceeds the sum of estimates of the undiscounted cash flows expected to result from the use and eventual disposition of the asset. When alternative courses of action to recover the carrying amount of a long-lived asset are under consideration, a probability-weighted approach is used in developing estimates of future undiscounted cash flows. If the carrying value of the long-lived asset is not recoverable based on these estimated future undiscounted cash flows, an impairment loss is measured as the excess of the asset s carrying value over its fair value, such that the asset s carrying value is adjusted to its estimated fair value.

We assess the fair value of long-lived assets using commonly accepted techniques and may use more than one source. Sources to determine fair value include, but are not limited to, recent third-party comparable sales, internally developed discounted cash flow analyses and analyses from outside advisors. Significant changes in market conditions resulting from events such as changes in natural gas available to our systems, the condition of an asset, a change in our intent to utilize the asset or a significant change in contracted revenues or regulatory recoveries would generally require us to reassess the cash flows related to the long-lived assets.

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

Unamortized Debt Premium, Discount and Expense. Premiums, discounts and expenses incurred with the issuance of outstanding long-term debt are amortized over the terms of the debt issues. Any call premiums or unamortized expenses associated with refinancing higher-cost debt obligations to finance regulated assets and operations are amortized consistent with regulatory treatment of those items, where appropriate.

Environmental Expenditures. We expense environmental expenditures related to conditions caused by past operations that do not generate current or future revenues. Environmental expenditures related to operations that generate current or future revenues are expensed or capitalized, as appropriate. Undiscounted liabilities are recorded when the necessity for environmental remediation becomes probable and the costs can be reasonably estimated, or when other potential environmental liabilities are reasonably estimable and probable.

Captive Insurance Reserves. We have captive insurance subsidiaries which provide insurance coverage to our consolidated subsidiaries as well as certain equity affiliates, on a limited basis, for various business risks and losses, such as workers compensation, property, business interruption and general liability. Liabilities include provisions for estimated losses incurred but not yet reported, as well as provisions for known claims which have been estimated on a claims-incurred basis. Incurred but not yet reported reserve estimates involve the use of assumptions and are based upon historical loss experience, industry data and other actuarial assumptions. Reserve estimates are adjusted in future periods as actual losses differ from historical experience.

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

Accounting For Sales of Stock by a Subsidiary. Sales of stock by a subsidiary are accounted for as equity transactions in those instances where a change in control does not take place.

Segment Reporting. Operating segments are components of an enterprise for which separate financial information is available and evaluated regularly by the chief operating decision maker in deciding how to allocate resources and evaluate performance. Two or more operating segments may be aggregated into a single reportable segment provided certain criteria are met. There is no such aggregation within our defined business segments. A description of our reportable segments, consistent with how business results are reported internally to management, and the disclosure of segment information is presented in Note 4.

Consolidated Statements of Cash Flows. Cash flows from discontinued operations are combined with cash flows from continuing operations within operating, investing and financing cash flows. Cash received from insurance proceeds are classified depending on the activity that resulted in the insurance proceeds. For example, business interruption insurance proceeds are included as a component of operating activities while insurance proceeds from damaged property are included as a component of investing activities. With respect to cash overdrafts, book overdrafts are included within operating cash flows while bank overdrafts are included within financing cash flows. Cash flows from borrowings and repayments under revolving credit facilities that had documented original maturities of 90 days or less are reported on a net basis as Net Increase (Decrease) in Revolving Credit Facilities Borrowings within financing activities.

Distributions from Unconsolidated Affiliates. We consider dividends received from unconsolidated affiliates which do not exceed cumulative equity in earnings subsequent to the date of investment to be a return on investment and classify these amounts as Cash Flows From Operating Activities within the accompanying Consolidated Statements of Cash Flows. Cumulative dividends received in excess of cumulative equity in earnings subsequent to the date of investment are considered to be a return of investment and are classified as Cash Flows From Investing Activities.

New Accounting Pronouncements. There were no significant accounting pronouncements adopted during 2012, 2011 or 2010 that had a material impact on our consolidated results of operations, financial position or cash flows.

2. Spectra Energy Partners, LP

Spectra Energy Partners, LP (Spectra Energy Partners) is our natural gas infrastructure master limited partnership. As of December 31, 2012, Spectra Energy owned 61% of Spectra Energy Partners, including a 2% general partner interest.

Maritimes & Northeast Pipeline, L.L.C. On October 31, 2012, Spectra Energy transferred a 38.76% interest in Maritimes & Northeast Pipeline, L.L.C. (M&N LLC) to Spectra Energy Partners for approximately $375 million, consisting of approximately $319 million in cash and $56 million in newly issued partnership units. The price received by Spectra Energy exceeded the book value of the M&N LLC investment. Therefore, this transfer of assets between entities resulted in an increase to Spectra Energy s Additional Paid-in Capital of $54 million ($34 million net of tax) and a decrease to Equity-Noncontrolling Interests of $54 million on the Consolidated Balance Sheet, representing the portion of the excess that was associated with the public unitholders of Spectra Energy Partners.

Big Sandy Pipeline, LLC. In 2011, Spectra Energy Partners acquired all of the ownership interests of Big Sandy Pipeline, LLC (Big Sandy) from EQT Corporation (EQT) for approximately $390 million. See Note 3 for further discussion.

Gulfstream Natural Gas System, LLC. In 2010, Spectra Energy transferred an additional 24.5% interest in Gulfstream Natural Gas System, LLC (Gulfstream) to Spectra Energy Partners for approximately $330 million, consisting of approximately $66 million in newly issued partnership units, the assumption of approximately $7 million in debt owed to a subsidiary of Spectra Energy and approximately $257 million in cash from borrowings under its revolving credit facility. The price received by Spectra Energy exceeded the book value of the Gulfstream investment. Therefore, this transfer of assets between entities resulted in an increase to Spectra Energy s Additional Paid-in Capital of $29 million ($19 million net of tax) and a decrease to Equity-Noncontrolling Interests of $29 million, representing the portion of the excess that was associated with the public unitholders of Spectra Energy Partners.

Sales of Spectra Energy Partners Common Units. 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 capital expenditures and acquisitions. In connection with the sale of the units, a $42 million gain ($26 million net of tax) to Additional Paid-in Capital and a $108 million increase in Equity Noncontrolling Interests were recorded in 2012.

In 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. See Note 3 for additional information on the acquisition of Big Sandy. In connection with the sale of the units, a $60 million gain ($38 million net of tax) to Additional Paid-in Capital and a $154 million increase in Equity Noncontrolling Interests were recorded in 2011.

In 2010, Spectra Energy Partners issued 6.9 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 from the issuances was $221 million (net proceeds to Spectra Energy was $216 million), with $209 million used to purchase qualifying investment-grade securities, $7 million used to pay the debt owed to a subsidiary of Spectra Energy and $5 million used for Spectra Energy Partners general partnership purposes. Spectra Energy

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Partners also borrowed $207 million of term debt using the investment-grade securities as collateral and paid off an equal amount of its outstanding revolving credit facility loan. In connection with the sale of the partner units, an $80 million gain ($50 million net of tax) to Additional Paid-in Capital and a $140 million increase in Equity Noncontrolling Interests were recorded in 2010.

3. Acquisitions and Dispositions

Acquisitions. We consolidate assets and liabilities from acquisitions as of the purchase date and include earnings from acquisitions in consolidated earnings after the purchase date. Assets acquired and liabilities assumed are recorded at estimated fair values on the date of acquisition. The purchase price less the estimated fair value of the acquired assets and liabilities meeting the definition of a business is recorded as goodwill. The allocation of the purchase price may be adjusted if additional information is received during the allocation period, which generally does not exceed one year from the consummation date.

Sand Hills and Southern Hills. On November 15, 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) NGL pipelines from DCP Midstream 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 ownership interests in the two pipelines. The Sand Hills pipeline will provide NGL transportation from the Permian Basin and Eagle Ford region to the premium NGL markets on the Gulf Coast. Southern Hills will provide NGL transportation from the Mid-Continent to Mont Belvieu, Texas. Our investments in Sand Hills and Southern Hills are included in Investments in and Loans to Unconsolidated Affiliates on our Consolidated Balance Sheets and Statements of Cash Flows.

Big Sandy. In 2011, Spectra Energy Partners completed the acquisition of Big Sandy from EQT for approximately $390 million in cash. Big Sandy s primary asset is a Federal Energy Regulatory Commission (FERC)-regulated natural gas pipeline system in eastern Kentucky. The Big Sandy natural gas pipeline system connects Appalachian and Huron Shale natural gas supplies to markets in the mid-Atlantic and northeast portions of the United States. The acquisition of Big Sandy, part of the U.S. Transmission segment, strengthens Spectra Energy Partners portfolio of fee-based natural gas assets and is consistent with its strategy of growth. The purchase price was greater than the sum of fair values of the net assets acquired, resulting in goodwill as noted below. The goodwill reflects the value of the strategic location of the pipeline and the opportunity to expand and grow the business.

Bobcat. In 2010, we acquired Bobcat Gas Storage assets and development project (Bobcat) from Haddington Energy Partners III LP and GE Energy Financial Services for $540 million, of which approximately $37 million was withheld pending certain outcomes. As of December 31, 2011, the remaining withheld amounts totaled $30 million, of which $10 million was recorded within Deferred Credits and Other Liabilities Regulatory and Other and $20 million was recorded within Current Liabilities Other on the Consolidated Balance Sheets. The $30 million was paid in 2012 and is included in Acquisitions, Net of Cash Acquired on our Consolidated Statements of Cash Flows. Strategically located on the Gulf Coast in southeastern Louisiana near Henry Hub, the Bobcat assets interconnect with five major interstate pipelines, including our Texas Eastern Transmission, LP (Texas Eastern) pipeline, and complement our existing pipeline and storage portfolio in the region. Bobcat is part of the U.S. Transmission segment. Storage infrastructure such as Bobcat plays a vital role in meeting customers needs for managing demand swings on a seasonal basis, satisfying the increasing demand for natural gas-fired power generation and providing customers with the advantage and flexibility to access all the major markets in the United States.

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The following table summarizes the fair values of the assets and liabilities acquired for Big Sandy and Bobcat as of the date of the respective acquisition:

	Purchase Price Allocation	
	Big Sandy	Bobcat
	(in millions)	
Purchase price	$ 390	$ 540
Working capital and other purchase adjustments		6
Total	390	546
Cash		17
Receivables		3
Property, plant and equipment, cost	196	350
Accounts payable		(8)
Other current liabilities		(2)
Deferred credits and other liabilities		(2)
Total assets acquired/liabilities assumed	196	358
Goodwill	$ 194	$ 188

Goodwill related to the acquisitions of Big Sandy and Bobcat is deductible for income tax purposes.

Pro forma results of operations reflecting these acquisitions as if those transactions had occurred as of the beginning of the periods presented in this report do not materially differ from actual reported results.

Dispositions. In 2011, we received payment of a $51 million note receivable, recorded as Other Investing Activities on our Consolidated Statements of Cash Flows, from the sale of certain entities to third parties in 2002.

Pending Acquisition. On December 10, 2012, we entered into a definitive agreement to purchase 100% of the ownership interests in the Express-Platte Pipeline System from Borealis Infrastructure, the Ontario Teachers Pension Plan and Kinder Morgan Energy Partners for $1.49 billion, consisting of $1.25 billion in cash and $240 million of acquired debt. The Express-Platte Pipeline System, which begins in Hardisty, Alberta, and terminates in Wood River, Illinois, is comprised of both the Express and Platte crude oil pipelines. The Express pipeline carries crude oil to U.S. refining markets in the Rockies area, specifically Billings and Laurel, Montana, and Casper, Wyoming. The Platte pipeline, which interconnects with Express pipeline in Casper, transports crude oil predominantly from the Bakken and western Canada to refineries in the Midwest. Completion of the transaction is subject to customary consents, regulatory approvals and closing conditions. The transaction is expected to close in the first half of 2013. Upon closing, a new reportable business segment, Liquids, will be formed that will consist of the Express-Platte Pipeline System assets and our direct equity investments in Sand Hills and Southern Hills.

4. Business Segments

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. Other also currently consists of our direct one-third equity investments in Sand Hills and Southern Hills until the closing of the acquisition of the Express-Platte Pipeline System assets.

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

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U.S. Transmission provides transportation and storage of natural gas for customers in various regions of the northeastern and southeastern United States and the Maritime Provinces in Canada. The natural gas transmission and storage operations in the U.S. are primarily subject to the rules and regulations of the FERC. Spectra Energy Partners, a master limited partnership, is part of the U.S. Transmission segment.

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

Western Canada Transmission & Processing provides transportation of natural gas, natural gas gathering and processing services, and NGLs extraction, fractionation, transportation, storage and marketing to customers in western Canada and the northern tier of the United States. This segment conducts business mostly through BC Pipeline, BC Field Services, and the NGL marketing and Canadian Midstream businesses. BC Pipeline and BC Field Services operations are primarily subject to the rules and regulations of Canada s National Energy Board (NEB).

Field Services gathers, processes, treats, compresses, transports and stores natural gas. In addition, this segment 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. DCP Midstream gathers raw natural gas through gathering systems located in nine major conventional and non-conventional 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 has a 28% ownership interest in DCP Midstream Partners, LP (DCP Partners), a master limited partnership.

Our reportable segments offer different products and services and are managed separately as business units. Management evaluates segment performance based on earnings before interest and taxes (EBIT), 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 short-term investments are managed centrally, so the associated realized and unrealized gains and losses from foreign currency transactions and interest and dividend income on those balances are excluded from the segments EBIT. Transactions between reportable segments are accounted for on the same basis as transactions with unaffiliated third parties.

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Business Segment Data

	Unaffiliated Revenues	Intersegment Revenues	Total Operating Revenues (a)	Segment EBIT/ Consolidated Earnings from Continuing Operations before Income Taxes (a) (in millions)	Depreciation and Amortization (a)	Capital and Investment Expenditures (b)	Segment Assets
2012							
U.S. Transmission	$ 1,888	$ 9	$ 1,897	$ 995	$ 282	$ 933	$ 12,630
Distribution	1,666		1,666	374	213	276	5,842
Western Canada Transmission & Processing	1,512	34	1,546	387	197	757	6,431
Field Services				279			1,235
Total reportable segments	5,066	43	5,109	2,035	692	1,966	26,138
Other	9	65	74	(112)	54	579	4,988
Eliminations		(108)	(108)				(539)
Interest expense				625			
Interest income and other (c)				117			
Total consolidated	$ 5,075	$	$ 5,075	$ 1,415	$ 746	$ 2,545	$ 30,587
2011							
U.S. Transmission	$ 1,891	$ 9	$ 1,900	$ 983	$ 272	$ 773	$ 11,783
Distribution	1,831		1,831	425	208	292	5,551
Western Canada Transmission & Processing	1,622	50	1,672	510	186	776	5,649
Field Services				449			1,157
Total reportable segments	5,344	59	5,403	2,367	666	1,841	24,140
Other	7	65	72	(104)	43	78	4,535
Eliminations		(124)	(124)				(537)
Interest expense				625			
Interest income and other (c)				106			
Total consolidated	$ 5,351	$	$ 5,351	$ 1,744	$ 709	$ 1,919	$ 28,138
2010							
U.S. Transmission	$ 1,816	$ 5	$ 1,821	$ 948	$ 258	$ 641	$ 11,120
Distribution	1,779		1,779	409	194	227	5,473
Western Canada Transmission & Processing	1,341	4	1,345	409	169	449	5,013
Field Services				335			1,101
Total reportable segments	4,936	9	4,945	2,101	621	1,317	22,707
Other	9	49	58	(38)	29	39	4,217
Eliminations		(58)	(58)				(238)
Interest expense				630			
Interest income and other (c)				73			
Total consolidated	$ 4,945	$	$ 4,945	$ 1,506	$ 650	$ 1,356	$ 26,686

(a) Excludes amounts associated with entities included in discontinued operations.
(b) 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, all part of U.S. Transmission. Includes $513 million of initial and subsequent equity investments in Sand Hills and Southern Hills in 2012 within the Other segment.
(c) Includes foreign currency transaction gains and losses and the add-back of noncontrolling interests related to segment EBIT.

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Geographic Data

	U.S.	Canada (in millions)	Consolidated
2012			
Consolidated revenues (a)	$ 1,762	$ 3,313	$ 5,075
Consolidated long-lived assets	10,952	14,875	25,827
2011			
Consolidated revenues (a)	1,754	3,597	5,351
Consolidated long-lived assets	10,231	13,772	24,003
2010			
Consolidated revenues (a)	1,688	3,257	4,945
Consolidated long-lived assets	9,382	13,225	22,607

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

5. Regulatory Matters

Regulatory Assets and Liabilities. We record assets and liabilities that result from the regulated ratemaking process that would not be recorded under GAAP for non-regulated entities. See Note 1 for further discussion.

	December 31, 2012	2011	Recovery/ Refund Period Ends
	(in millions)		
Regulatory Assets (a,b)			
Net regulatory asset related to income taxes (c)	$ 1,100	$ 940	(d)
Project costs	21	26	2036
Vacation accrual	19	20	(e)
Deferred debt expense/premium (f)	38	44	(d)
Environmental clean-up costs	7	6	2017
Gas in storage (included in Inventory)	15	53	2013
Gas purchase costs (included in Other Current Assets) (g)	13	17	2013
Other	51	36	(h)
Total Regulatory Assets	$ 1,264	$ 1,142	
Regulatory Liabilities (b)			
Removal costs (f,i)	$ 452	$ 424	(j)
Gas purchase costs (k,l)	50	53	2013
Pipeline rate credit (i)	28	29	(d)
Storage and transportation liability (k)		12	2013
Earnings sharing liability (k)	3	20	2013
Other (i)	97	24	2013
Total Regulatory Liabilities	$ 630	$ 562	

(a) Included in Regulatory Assets and Deferred Debits unless otherwise noted.
(b) All regulatory assets and liabilities are excluded from rate base unless otherwise noted.
(c) All amounts are expected to be included in future rate filings.

(d) Recovery/refund is over the life of the associated asset or liability.
(e) Recoverable in future periods.
(f) Included in rate base.
(g) Amounts settled in cash annually through transportation rates in accordance with FERC gas tariffs.
(h) Recovery/refund period currently unknown.
(i) Included in Deferred Credits and Other Liabilities Regulatory and Other.
(j) Liability is extinguished as the associated assets are retired.
(k) Included in Other Current Liabilities.
(l) Includes certain costs which are settled in cash annually through transportation rates in accordance with OEB gas tariffs.

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Rate Related Information

M&N LLC. M&N LLC operates under rates approved by the FERC in a 2010 settlement.

Maritimes & Northeast Pipeline Limited Partnership (M&N LP). M&N LP negotiated a three-year toll settlement covering 2011 2013, which received unanimous approval from M&N LP s shippers and was approved by the NEB on January 12, 2012. The settlement will not have a material effect on our consolidated results of operations, financial position or cash flows.

Algonquin Gas Transmission, LLC (Algonquin). Algonquin continues to operate under rates approved by the FERC in a 1999 settlement.

Gulfstream. Gulfstream operates under rates approved by the FERC in 2007. In 2007, the FERC issued an order approving Gulfstream s Phase III expansion project. That order also required Gulfstream to file a Cost and Revenue Study three years after the Phase III facilities went into service. Gulfstream filed the Cost and Revenue Study and the FERC accepted the filing on August 6, 2012. There were no changes to rates.

East Tennessee Natural Gas, LLC (East Tennessee). East Tennessee continues to operate under rates approved by the FERC in a 2005 settlement.

Ozark Gas Transmission, LLC (Ozark). Ozark continues to operate under rates approved by the FERC in 2000. In 2011, Ozark reached a settlement agreement with customers in a FERC rate proceeding that included a rate moratorium until October 1, 2012 and a requirement to file a rate case by October 1, 2015.

Saltville Gas Storage Company L.L.C. (Saltville). Saltville continues to operate under rates approved by the FERC in a 2008 settlement. Pursuant to the settlement, Saltville is required to file a rate case by October 1, 2013.

Texas Eastern. Texas Eastern continues to operate under rates approved by the FERC in 1998 in an uncontested settlement with its customers.

Southeast Supply Header, LLC (SESH). SESH continues to operate under rates approved by the FERC in 2008. That order required SESH to file a Cost and Revenue Study at the end of three years of operations. SESH filed the Cost and Revenue Study and the FERC accepted the filing on July 26, 2012. There was no change to rates.

Big Sandy. Big Sandy continues to operate under rates approved by the FERC in 2006.

Union Gas. As 2012 was the final year in Union Gas current multi-year incentive regulation framework, Union Gas filed an application with the OEB in November 2011 to set their distribution rates effective January 1, 2013. As part of the 2013 rates hearing process, Union Gas conducted settlement negotiations with its intervening parties. A settlement agreement was reached on most capital and rate base issues, and on all operating costs. That settlement agreement was accepted by the OEB on July 10, 2012. The unsettled issues, including operating revenue, cost of capital and rate design, were the subjects of a hearing. On October 25, 2012, the OEB issued its decision on the unsettled issues. The average annual impact on a customer s total bill will range 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.

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In August 2012, the OEB determined it would review the treatment of 2011 revenues derived from the optimization of Union Gas upstream transportation contracts as part of the application to dispose of 2011 year-end deferral account and other balances. Union Gas has historically and continues to record the optimization of upstream transportation contracts as revenues. The OEB decision on Union Gas 2013 rates application issued October 25, 2012 found that, among other things, the revenues associated with the optimization of upstream transportation contracts effective 2013 are to be considered a reduction of natural gas supply costs, the majority of which are to be passed through to customers. On November 19, 2012, the OEB issued its decision on the treatment of revenues derived from the optimization of Union Gas upstream transportation contracts for 2011. Similar to its finding in the 2013 rate case, the OEB determined that certain optimization revenue for 2011 will be treated as a reduction to natural gas supply costs. Union Gas has appealed this decision to the Ontario Divisional Court (the Court) on the basis of impermissible retroactive ratemaking. A hearing and decision by the Court is expected by the end of 2013. The above-mentioned finding on the treatment of certain optimization revenues, including the effect on the treatment of optimization revenues for 2012, resulted in a charge of $38 million to Distribution of Natural Gas on the Consolidated Statement of Operations in 2012.

Union Gas has regulatory assets of $300 million as of December 31, 2012 and $230 million as of December 31, 2011 related to deferred income tax liabilities. Under the current OEB-authorized rate structure, income tax costs are recovered in rates based on the current income tax payable and do not include accruals for deferred income tax. However, as income taxes become payable as a result of the reversal of timing differences that created the deferred income taxes, it is expected that rates will be adjusted to recover these taxes. Since substantially all of these timing differences are related to property, plant and equipment costs, recovery of these regulatory assets is expected to occur over the life of those assets.

Union Gas has regulatory liabilities associated with plant removal costs of $447 million as of December 31, 2012 and $418 million as of December 31, 2011. These regulatory liabilities represent collections from customers under approved rates for future asset removal activities that are expected to occur associated with its regulated facilities.

In addition, Union Gas has regulatory liabilities of $50 million as of December 31, 2012 and $53 million as of December 31, 2011 representing gas cost collections from customers under approved rates that exceeded the actual cost of gas for the associated periods. Union Gas files quarterly with the OEB to ensure that customers rates reflect future expected prices based on published forward-market prices. The difference between the approved and the actual cost of gas is deferred for future repayment to or refund from customers and is a component of quarterly gas commodity rates.

BC Pipeline and BC Field Services. BC Pipeline and its customers reached a toll settlement agreement, which was approved by the NEB in January 2011, regarding final tolls for transmission services for 2011, 2012 and 2013.

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

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The BC Pipeline and BC Field Services businesses in Western Canada have regulatory assets of $682 million as of December 31, 2012 and $599 million as of December 31, 2011 related to deferred income tax liabilities. Under the current NEB-authorized rate structure, income tax costs are recovered in tolls based on the current income tax payable and do not include accruals for deferred income tax. However, as income taxes become payable as a result of the reversal of timing differences that created the deferred income taxes, it is expected that transportation and field services tolls will be adjusted to recover these taxes. Since most of these timing differences are related to property, plant and equipment costs, this recovery is expected to occur over a 20 to 30 year period.

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

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

6. Income Taxes

Income Tax Expense Components

	2012	2011 (in millions)	2010
Current income taxes			
Federal	$ 102	$ 4	$ 105
State	5	9	22
Foreign	52	100	38
Total current income taxes	159	113	165
Deferred income taxes			
Federal	174	328	168
State	33	17	13
Foreign	4	29	37
Total deferred income taxes	211	374	218
Income tax expense from continuing operations	370	487	383
Income tax expense (benefit) from discontinued operations	2	14	(17)
Total income tax expense	$ 372	$ 501	$ 366

Earnings from Continuing Operations before Income Taxes

	2012	2011 (in millions)	2010
Domestic	$ 912	$ 1,049	$ 899
Foreign	503	695	607
Total earnings from continuing operations before income taxes	$ 1,415	$ 1,744	$ 1,506

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

	2012	2011	2010
		(in millions)	
Income tax expense, computed at the statutory rate of 35%	$ 495	$ 610	$ 527
State income tax, net of federal income tax effect	19	21	18
Tax differential on foreign earnings	(110)	(98)	(104)
Domestic production activities deduction	(1)	(1)	(6)
Noncontrolling interests	(37)	(34)	(28)
British Columbia harmonization of tax pools			(24)
Valuation allowance	1	1	1
Other items, net	3	(12)	(1)
Total income tax expense from continuing operations	$ 370	$ 487	$ 383
Effective tax rate	26.1%	27.9%	25.4%

Net Deferred Income Tax Liability Components

	December 31, 2012	December 31, 2011
	(in millions)	
Deferred credits and other liabilities	$ 358	$ 342
Other	51	60
Total deferred income tax assets	409	402
Valuation allowance	(25)	(21)
Net deferred income tax assets	384	381
Investments and other assets	(1,339)	(1,196)
Accelerated depreciation rates	(3,085)	(2,875)
Regulatory assets and deferred debits	(326)	(271)
Total deferred income tax liabilities	(4,750)	(4,342)
Total net deferred income tax liabilities	$ (4,366)	$ (3,961)

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

	December 31, 2012	December 31, 2011
	(in millions)	
Other current assets	$ 24	$ 11
Other current liabilities	(32)	(32)
Deferred credits and other liabilities	(4,358)	(3,940)
Total net deferred income tax liabilities	$ (4,366)	$ (3,961)

At December 31, 2012, we had an unused state net operating loss carryforward of approximately $230 million that expires at various times beginning in 2015. The deferred tax asset attributable to the state net operating loss carryovers is $13 million (net of federal impacts) at December 31, 2012. We had valuation allowances of $3 million at December 31, 2012 and $2 million at December 31, 2011 against the deferred tax asset attributable to the state net operating loss and credit carryovers.

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At December 31, 2012, we had a foreign net operating loss carryforward of $65 million that expires at various times beginning in 2015. The deferred tax asset attributable to the foreign net operating loss is $16 million. At December 31, 2012, we also had a foreign capital loss carryforward of $177 million with an indefinite expiration period. The deferred tax asset attributable to the foreign capital loss carryforward is $22 million. We had valuation allowances of $22 million at December 31, 2012 and $20 million at December 31, 2011 against the deferred tax asset related to the foreign capital loss carryforward.

Reconciliation of Gross Unrecognized Income Tax Benefits

	2012	2011	2010
		(in millions)	
Balance at January 1	$ 76	$ 82	$ 61
Increases related to prior year tax positions	5	10	9
Decreases related to prior year tax positions		(6)	(2)
Increases related to current year tax positions	2		23
Settlements	(2)		
Reductions due to lapse of statute of limitations	(2)	(9)	(11)
Foreign currency translation	1	(1)	2
Balance at December 31	$ 80	$ 76	$ 82

Unrecognized tax benefits totaled $80 million at December 31, 2012. Of this, $46 million would reduce the annual effective tax rate if recognized on or after January 1, 2013. We recorded a net increase of $4 million in gross unrecognized tax benefits during 2012. This was a result of $6 million attributable to deferred tax liabilities and foreign currency exchange rate fluctuations offset by a $2 million decrease in income tax expense.

We recognize potential accrued interest and penalties related to unrecognized tax benefits as interest expense and as other expense, respectively. We recognized interest expense of $1 million in 2012 and $4 million in 2011 related to unrecognized tax benefits. Accrued interest and penalties totaled $25 million at December 31, 2012 and $24 million at December 31, 2011.

Although uncertain, we believe the total amount of unrecognized tax benefits will not materially change prior to December 31, 2013.

In connection with the spin-off of Spectra Energy from Duke Energy Corporation (Duke Energy) in 2007, we entered into an indemnification agreement with Duke Energy related to certain federal and state income taxes, including interest and penalties, for periods in which we were included in a Duke Energy consolidated, combined or unitary filing for years ended December 31, 2006 and prior. The indemnifications total $63 million, of which $49 million is included in Current Liabilities-Other and $14 million is included in Deferred Credits and Other Liabilities-Regulatory and Other on the Consolidated Balance Sheet as of December 31, 2012. Pursuant to the agreement with Duke Energy, there are no outstanding federal and state indemnification liabilities prior to 2004.

We remain subject to examination for Canada income tax return filings for years 2006 through 2011 and U.S. income tax return filings for 2007 through 2011.

Our foreign subsidiaries undistributed earnings of approximately $2.1 billion at December 31, 2012 are indefinitely invested outside the United States and, accordingly, no U.S. federal or state income taxes have been provided on those earnings. Upon distribution of those earnings, we may be subject to both foreign withholding taxes and U.S. income taxes, net of allowable foreign tax credits. The amount of such additional taxes would be dependent on several factors, including the size and timing of the distribution and the availability of foreign tax credits. As a result, the determination of the potential amount of unrecognized withholding and deferred income taxes is not practicable.

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7. Discontinued Operations

Discontinued operations is mostly comprised of the net effects of a settlement arrangement related to prior liquefied natural gas (LNG) contracts and an immaterial positive income tax adjustment in 2010 related to previously discontinued operations.

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

	2012	2011 (in millions)	2010
Operating revenues	$ 99	$ 251	$ 126
Pre-tax earnings (loss)	4	39	(11)
Income tax expense (benefit)	2	14	(17)
Income from discontinued operations, net of tax	2	25	6

Spectra Energy LNG Sales, Inc. (Spectra Energy LNG) reached a settlement agreement in 2007 related to an arbitration proceeding regarding Spectra Energy LNG s claims for the period prior to May 2002 under certain liquefied natural gas LNG transportation contracts with Sonatrach and Sonatrading Amsterdam B.V. (Sonatrach). Spectra Energy LNG was one of the entities contributed to us by Duke Energy in connection with our spin-off from Duke Energy and has been reflected as discontinued operations. In 2008, Sonatrach and Spectra Energy entered into a settlement agreement under which Spectra Energy LNG s claims for the period after May 2002 were to be satisfied pursuant to commercial transactions involving the purchase of propane by Spectra Energy Propane, LLC (a subsidiary) from Sonatrach. We subsequently entered into associated agreements with what are now affiliates of DCP Midstream for the sale of this propane. Net purchases and sales of propane under these arrangements are reflected as discontinued operations within the Other business segment. Income From Discontinued Operations, Net of Tax in 2010 includes an expense of $17 million ($11 million after-tax) for payments by us to a DCP Midstream affiliate for reimbursement of damages resulting from an alleged breach by Sonatrach of certain scheduled propane deliveries to us in the fourth quarter of 2010. We recovered $21 million ($14 million after-tax) of propane deliveries in 2011 from Sonatrach to recover these losses, recorded within Income From Discontinued Operations. Purchases and sales of propane under these agreements ended in 2012.

8. Earnings per Common Share

Basic earnings per common share (EPS) is computed by dividing net income from controlling interests by the weighted-average number of common shares outstanding during the period. Diluted EPS is computed by dividing net income from controlling interests by the diluted weighted-average number of common shares outstanding during the period. Diluted EPS reflects the potential dilution that could occur if securities or other agreements to issue common stock, such as stock options, stock-based performance unit awards and phantom stock awards, were exercised, settled or converted into common stock.

Weighted-average shares used to calculate diluted EPS includes the effect of certain options and restricted stock awards. Certain other options and stock awards related to less than one million shares in 2012, four million shares in 2011 and ten million shares in 2010 were not included in the calculation of diluted EPS because either the option exercise prices were greater than the average market price of the shares during these periods or performance measures related to the awards had not yet been met.

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The following table presents our basic and diluted EPS calculations:

	2012	2011	2010
	(in millions, except per-share amounts)		
Income from continuing operations, net of tax controlling interests	$ 938	$ 1,159	$ 1,043
Income from discontinued operations, net of tax controlling interests	2	25	6
Net income controlling interests	$ 940	$ 1,184	$ 1,049
Weighted average common shares, outstanding			
Basic	653	650	648
Diluted	656	653	650
Basic earnings per common share			
Continuing operations	$ 1.44	$ 1.78	$ 1.61
Discontinued operations, net of tax		0.04	0.01
Total basic earnings per common share	$ 1.44	$ 1.82	$ 1.62
Diluted earnings per common share			
Continuing operations	$ 1.43	$ 1.77	$ 1.60
Discontinued operations, net of tax		0.04	0.01
Total diluted earnings per common share	$ 1.43	$ 1.81	$ 1.61

9. Inventory

The components of inventory are as follows:

	December 31, 2012	December 31, 2011
	(in millions)	
Natural gas	$ 200	$ 263
NGLs	31	58
Materials and supplies	78	72
Total inventory	$ 309	$ 393

Non-cash charges totaling $14 million in 2012 ($10 million after tax) were recorded to Natural Gas and Petroleum Products Purchased on the Consolidated Statements of Operations to reduce propane inventory at our Empress operations at Western Canada Transmission & Processing to estimated net realizable value.

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

Investments in affiliates for which we are not the primary beneficiary, but over which we have significant influence, are accounted for using the equity method. As of December 31, 2012 and 2011, the carrying amounts of investments in affiliates approximated the amounts of underlying equity in net assets. We received distributions from our equity investments of $324 million in 2012, $516 million in 2011 and $391 million in 2010. Cumulative undistributed earnings of unconsolidated affiliates totaled $352 million at December 31, 2012 and $278 million at December 31, 2011.

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U.S. Transmission. As of December 31, 2012, investments are mostly comprised of a 31% effective interest in Gulfstream and 50% interests in SESH and Steckman Ridge, LP (Steckman Ridge). Gulfstream is an interstate natural gas pipeline that extends from Mississippi and Alabama across the Gulf of Mexico to Florida. SESH is an interstate natural gas pipeline that extends from northeast Louisiana to Mobile County, Alabama where it connects to the Gulfstream system. Steckman Ridge is a storage project located in Bedford County, Pennsylvania.

We have loans outstanding to Steckman Ridge in connection with the construction of its storage facilities. The loans carry market-based interest rates and are due the earlier of December 31, 2017 or coincident with the closing of any long-term financings by Steckman Ridge. The loan receivable from Steckman Ridge, including accrued interest, totaled $71 million at both December 31, 2012 and 2011. We recorded interest income on the Steckman Ridge loan of $1 million in each of 2012, 2011 and 2010.

Field Services. Our most significant investment in unconsolidated affiliates is our 50% investment in DCP Midstream which is accounted for under the equity method of accounting. DCP Midstream is a limited liability company which is a pass-through entity for U.S. income tax purposes. DCP Midstream also owns an entity which files its own federal, foreign and state income tax returns. Income tax expense related to that entity is included in the income tax expense of DCP Midstream. Therefore, DCP Midstream s net income attributable to members interests does not include income taxes for earnings which are passed through to the members based upon their ownership percentage. We recognize the tax effects of our share of DCP Midstream s pass-through earnings in Income Tax Expense from Continuing Operations in the Consolidated Statements of Operations.

In 2012, 2011 and 2010, DCP Midstream recorded to equity gains on additional sales of common units of DCP Partners. Our proportionate 50% share, totaling $36 million in 2012, $17 million in 2011 and $30 million in 2010, is recorded in Equity in Earnings of Unconsolidated Affiliates in the Consolidated Statements of Operations.

Other. Our direct one-third equity investments in Sand Hills and Southern Hills are currently classified within Other until the closing of the acquisition of the Express-Platte Pipeline System assets at which time a new reportable business segment, Liquids, will be formed that will include our investments in Sand Hills and Southern Hills. The Sand Hills pipeline will provide NGL transportation from the Permian Basin and Eagle Ford shale region to the premium NGL markets on the Gulf Coast. Southern Hills will provide NGL transportation from the Mid-Continent to Mont Belvieu, Texas. Sand Hills and Southern Hills are currently under construction.

Investments in and Loans to Unconsolidated Affiliates

	December 31, 2012			December 31, 2011		
	Domestic	International	Total	Domestic	International	Total
			(in millions)			
U.S. Transmission	$ 896	$	$ 896	$ 918	$	$ 918
Distribution		17	17		18	18
Western Canada Transmission & Processing		28	28		19	19
Field Services	1,235		1,235	1,109		1,109
Other	516		516			
Total	$ 2,647	$ 45	$ 2,692	$ 2,027	$ 37	$ 2,064

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Equity in Earnings of Unconsolidated Affiliates

	2012 Domestic	2012 International	2012 Total	2011 Domestic	2011 International	2011 Total	2010 Domestic	2010 International	2010 Total
					(in millions)				
U.S. Transmission	$ 102	$	$ 102	$ 98	$	$ 98	$ 94	$	$ 94
Western Canada Transmission & Processing		1	1		2	2		1	1
Field Services	279		279	449		449	335		335
Total	$ 381	$ 1	$ 382	$ 547	$ 2	$ 549	$ 429	$ 1	$ 430

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

Statements of Operations

	2012 DCP Midstream	2012 Other	2012 Total	2011 DCP Midstream	2011 Other	2011 Total	2010 DCP Midstream	2010 Other	2010 Total
					(in millions)				
Operating revenues	$ 10,171	$ 511	$ 10,682	$ 12,982	$ 469	$ 13,451	$ 10,981	$ 483	$ 11,464
Operating expenses	9,427	217	9,644	11,868	197	12,065	10,138	203	10,341
Operating income	744	294	1,038	1,114	272	1,386	843	280	1,123
Net income	583	203	786	924	188	1,112	619	223	842
Net income attributable to members interests	486	203	689	863	188	1,051	592	223	815

Balance Sheets

	December 31, 2012 DCP Midstream	December 31, 2012 Other	December 31, 2012 Total	December 31, 2011 DCP Midstream	December 31, 2011 Other	December 31, 2011 Total
			(in millions)			
Current assets	$ 1,289	$ 220	$ 1,509	$ 1,577	$ 167	$ 1,744
Non-current assets	9,495	4,823	14,318	7,835	3,286	11,121
Current liabilities	(2,775)	(117)	(2,892)	(2,647)	(46)	(2,693)
Non-current liabilities	(4,692)	(1,669)	(6,361)	(4,076)	(1,667)	(5,743)
Equity total	3,317	3,257	6,574	2,689	1,740	4,429
Equity noncontrolling interests	(913)		(913)	(537)		(537)
Equity controlling interests	$ 2,404	$ 3,257	$ 5,661	$ 2,152	$ 1,740	$ 3,892

Related Party Transactions

DCP Midstream. DCP Midstream processes certain of our pipeline customers gas to meet gas quality specifications in order to be transported on our Texas Eastern system. DCP Midstream processes the gas and sells the NGLs that are extracted from the gas. A portion of the proceeds from those sales are retained by DCP Midstream and the balance is remitted to us. We received proceeds of $53 million in 2012, $70 million in 2011 and $82 million in 2010 from DCP Midstream related to those sales, classified as Other Operating Revenues in our Consolidated Statements of Operations.

As discussed in Note 7, we entered into a propane sales agreement with an affiliate of DCP Midstream in 2008. We recorded revenues of $99 million in 2012, $251 million in 2011 and $85 million in 2010 associated with this agreement, as well as an expense of $17 million in 2010, classified within Income From Discontinued Operations, Net of Tax. Sales of propane under this agreement ended in 2012.

In addition to the above, we recorded other revenues from DCP Midstream and its affiliates totaling $12 million in 2012, $11 million in 2011 and $8 million in 2010, primarily within Transportation, Storage and Processing of Natural Gas and $14 million in 2012 within Sales of Natural Gas Liquids.

We had accounts receivable from DCP Midstream and its affiliates of $3 million at December 31, 2012 and $8 million at December 31, 2011. In addition, we had distributions receivable from DCP Midstream of $47 million at December 31, 2011 recorded within Receivables on the Consolidated Balance Sheet. Total distributions received from DCP Midstream were $203 million in 2012, $395 million in 2011 and $288 million in 2010, classified as Cash Flows from Operating Activities Distributions Received From Unconsolidated Affiliates.

On November 15, 2012, we acquired direct one-third ownership interests in Sand Hills and Southern Hills from DCP Midstream for $459 million. See Note 3 for further discussion.

Other. We provide certain administrative and other services to our equity investment operating entities. We recorded recoveries of costs from these affiliates of $70 million in 2012, $28 million in 2011 and $23 million in 2010. Outstanding receivables from these affiliates totaled $3 million at both December 31, 2012 and 2011.

See also Notes 3, 16 and 18 for additional related party information.

11. Marketable Securities and Restricted Funds

We routinely invest excess cash and various restricted balances in securities such as commercial paper, bankers acceptances, corporate debt securities, treasury bills and money market funds in the United States and Canada. We do not purchase marketable securities for speculative purposes, nor do we routinely sell marketable securities prior to their scheduled maturity dates. Therefore, we do not have any securities classified as trading securities. A portion of our investments of restricted funds, primarily insurance-related funds, are classified as available-for-sale (AFS) marketable securities as they may occasionally be sold prior to their scheduled maturity dates due to unexpected cash needs. Initial investments in securities are classified as purchases of the respective type of securities (AFS marketable securities or held-to-maturity (HTM) marketable securities). Maturities of securities are classified within proceeds from sales and maturities of securities in the Consolidated Statements of Cash Flows.

AFS Securities. AFS securities are as follows:

	Estimated Fair Value December 31,	
	2012	2011
	(in millions)	
Corporate debt securities	$ 164	$ 18
Canadian government securities		14
Money market funds	1	3
Total available-for-sale investments	$ 165	$ 35

We had $14 million of restricted AFS securities classified as Current Assets Other as of December 31, 2011, and $142 million and $3 million classified as Investments and Other Assets Other at December 31, 2012 and 2011, respectively.

At December 31, 2012, the weighted average contractual maturity of outstanding AFS securities was less than one year.

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There were no material gross unrealized holding gains or losses associated with investments in AFS securities at December 31, 2012 or 2011.

During the fourth quarter of 2012, we invested the proceeds from Spectra Energy Partners issuance of common units in AFS marketable securities. These investments, which totaled $141 million as of December 31, 2012 and are classified as Investments and Other Assets Other on the Consolidated Balance Sheet, are restricted for the purpose of funding Spectra Energy Partners capital expenditures and acquisitions.

During 2010, we invested a portion of the proceeds from Spectra Energy Partners issuance of common units to the public in AFS marketable securities. These investments were pledged as collateral against Spectra Energy Partners term loan. Spectra Energy Partners term loan was repaid in 2011 and the related investments were liquidated.

HTM Securities. HTM securities are as follows:

	Estimated Fair Value December 31, 2012	Estimated Fair Value December 31, 2011
	(in millions)	
Canadian government securities	$ 210	$ 107
Bankers acceptances	52	55
Total held-to-maturity investments	$ 262	$ 162

Restricted HTM marketable securities of $76 million as of December 31, 2012 are classified as Current Assets Other, and $186 million and $162 million at December 31, 2012 and 2011, respectively, are classified as Investments and Other Assets Other. These securities are restricted funds pursuant to certain M&N LP debt agreements. These funds, plus future cash from operations that would have otherwise been available for distribution to the partners of M&N LP, were required to be placed in escrow until the balance in escrow was sufficient to fund all future debt service on the M&N LP notes. There were sufficient funds held in escrow to fund all future debt service on the M&N LP notes as of December 31, 2012.

At December 31, 2012, the weighted average contractual maturity of outstanding HTM securities was one year.

There were no material gross unrecognized holding gains or losses associated with investments in HTM securities at December 31, 2012 or December 31, 2011.

Other Restricted Funds. In addition to the portions of the AFS and HTM securities that were restricted funds as described above, we had restricted funds totaling $21 million and $35 million at December 31, 2012 and 2011, respectively, classified as Current Assets Other, and $79 million at December 31, 2011 classified as Investments and Other Assets Other. These restricted funds are related to additional amounts for the M&N LP debt service requirements and insurance.

Changes in restricted balances are presented within Cash Flows from Investing Activities on our Consolidated Statements of Cash Flows.

Interest income. Interest income totaled $6 million in 2012, $12 million in 2011 and $3 million in 2010, and is included in Other Income and Expenses, Net on the Consolidated Statements of Operations.

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12. Goodwill

The following table presents activity within goodwill based on the reporting unit determination:

	U. S. Transmission	Distribution	Western Canada Transmission & Processing	Total
		(in millions)		
December 31, 2010	$ 2,669	$ 873	$ 763	$ 4,305
Acquisitions (a)	194			194
Foreign currency translation	(44)	(18)	(17)	(79)
December 31, 2011	2,819	855	746	4,420
Foreign currency translation	49	23	21	93
December 31, 2012	$ 2,868	$ 878	$ 767	$ 4,513

(a) Associated with the acquisition of Big Sandy. See Note 3 for further discussion.

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

	December 31, 2012	December 31, 2011
	(in millions)	
U.S. Transmission	$ 1,882	$ 1,832
Distribution	875	852
Western Canada Transmission & Processing	728	709

Our Empress NGL business, a reporting unit within Western Canada Transmission & Processing, is significantly affected by fluctuations in commodity prices. 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 and concluded there was no impairment of goodwill. With respect to all reporting units, there were no impairments of goodwill recorded in 2012, 2011 or 2010. See Note 1 for discussion of goodwill impairment testing.

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13. Property, Plant and Equipment

	Estimated Useful Life (years)	December 31, 2012	2011
		(in millions)	
Plant			
Natural gas transmission	15 100	$ 13,366	$ 12,555
Natural gas distribution	27 60	3,022	2,795
Gathering and processing facilities	25-40	4,035	3,535
Storage	5 122	1,942	1,892
Land rights and rights of way	21 122	467	470
Other buildings and improvements	10 50	120	103
Equipment	3 40	352	326
Vehicles	5 20	114	111
Land		110	96
Construction in process		1,884	1,305
Software	4 10	486	392
Other	5 82	359	352
Total property, plant and equipment		26,257	23,932
Total accumulated depreciation		(5,936)	(5,323)
Total accumulated amortization		(416)	(351)
Total net property, plant and equipment		$ 19,905	$ 18,258

We had no material capital leases at December 31, 2012 or 2011.

Almost 90% of our property, plant and equipment is regulated with estimated useful lives based on rates approved by the applicable regulatory authorities in the United States and Canada: the FERC, the NEB and the OEB. Composite weighted-average depreciation rates were 3.14% for 2012, 3.18% for 2011 and 3.14% for 2010.

Amortization expense of intangible assets totaled $81 million in 2012, $70 million in 2011 and $58 million in 2010. Estimated amortization expense for the next five years follows:

	Estimated Amortization Expense (in millions)
2013	$ 63
2014	55
2015	46
2016	34
2017	22

14. Asset Retirement Obligations

Our asset retirement obligations relate mostly to the retirement of certain gathering pipelines and processing facilities, obligations related to right-of-way agreements and contractual leases for land use. However, we have determined that a significant portion of our assets have an indeterminate life, and as such, the fair values of those associated retirement obligations are not reasonably estimable. These assets include onshore and some offshore pipelines, and certain processing plants and distribution facilities, whose retirement dates will depend mostly on the various natural gas supply sources that connect to our systems and the ongoing demand for natural gas usage in the markets we serve. We expect these supply sources and market demands to continue for the foreseeable future, therefore we are unable to estimate retirement dates that would result in asset retirement obligations.

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

Reconciliation of Changes in Asset Retirement Obligation Liabilities

	2012	2011
	(in millions)	
Balance at beginning of year	$ 173	$ 157
Accretion expense	9	8
Revisions in estimated cash flows	3	12
Foreign currency exchange impact	5	(3)
Liabilities settled	(2)	(1)
Balance at end of year (a)	$ 188	$ 173

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

15. Debt and Credit Facilities

Summary of Debt and Related Terms

	Weighted-Average Interest Rate	Year Due	December 31, 2012	2011
			(in millions)	
Unsecured debt	5.9%	2013 2041	$ 11,176	$ 10,233
Secured debt	5.7%	2013 2019	342	367
Long-term debt principal (including current maturities)			11,518	10,600
Change in fair value of debt hedged		2013 2018	50	56
Unamortized debt discount and premium, net			(13)	(15)
Other unamortized items			19	30
Total other non-principal amounts			56	71
Commercial paper (a)	0.8%		1,259	1,052
Total debt (b)			12,833	11,723
Current maturities of long-term debt			(921)	(525)
Commercial paper (c)			(1,259)	(1,052)
Total long-term debt			$ 10,653	$ 10,146

(a) The weighted-average days to maturity was 14 days as of December 31, 2012 and 12 days as of December 31, 2011.
(b) As of December 31, 2012 and 2011, respectively, $5,560 million and $5,067 million of debt was denominated in Canadian dollars.
(c) Weighted-average rates on outstanding commercial paper were 0.8% as of December 31, 2012 and 0.7% as of December 31, 2011.

Secured Debt. Secured debt as of December 31, 2012 and 2011 includes project financing for M&N LP. Ownership interests in M&N LP and certain of its accounts, revenues, business contracts and other assets are pledged as collateral.

Floating Rate Debt. Unsecured, secured and other debt included approximately $1,259 million of floating-rate debt as of December 31, 2012 and $1,052 million as of December 31, 2011. The weighted average interest rate of borrowings outstanding that contained floating rates was 0.8% at December 31, 2012 and 0.7% at December 31, 2011.

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Annual Maturities

	December 31, 2012 (in millions)
2013	$ 921
2014	1,195
2015	342
2016	760
2017	588
Thereafter	7,768
Total long-term debt, including current maturities (a)	$ 11,574

(a) Excludes commercial paper of $1,259 million.

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

Available Credit Facilities and Restrictive Debt Covenants

			Outstanding at December 31, 2012				
	Expiration Date	Total Credit Facilities Capacity	Commercial Paper	Term Loan	Letters of Credit	Total	Available Credit Facilities Capacity
				(in millions)			
Spectra Energy Capital, LLC							
Multi-year syndicated (a)	2016	$ 1,500	$ 514	$ n/a	$ 5	$ 519	$ 981
Delayed-draw syndicated term loan (a,b)	2015	1,200	n/a		n/a		1,200
Westcoast							
Multi-year syndicated (c)	2016	302	32	n/a		32	270
Union Gas							
Multi-year syndicated (d)	2016	403	377	n/a		377	26
Spectra Energy Partners							
Multi-year syndicated (e)	2016	700	336	n/a		336	364
Total		$ 4,105	$ 1,259	$	$ 5	$ 1,264	$ 2,841

(a) Revolving credit facility and term loan contain a covenant requiring the Spectra Energy Corp consolidated debt-to-total capitalization ratio, as defined in the agreements, to not exceed 65%. This ratio was 58% at December 31, 2012.

(b) Term loan agreement allows for up to four borrowings prior to March 1, 2013.

(c) U.S. dollar equivalent at December 31, 2012. The credit facility is 300 million Canadian dollars and contains a covenant that requires the Westcoast non-consolidated debt-to-total capitalization ratio to not exceed 75%. The ratio was 51% at December 31, 2012.

(d) U.S. dollar equivalent at December 31, 2012. The credit facility is 400 million Canadian dollars and contains a covenant that requires the Union Gas debt-to-total capitalization ratio to not exceed 75% and a provision which requires Union Gas to repay all borrowings under the facility for a period of two days during the second quarter of each year. The ratio was 68% at December 31, 2012.

(e) Credit facility contains a covenant that requires Spectra Energy Partners to maintain a ratio of total Debt-to-Adjusted Earnings Before Interest, Taxes, Depreciation and Amortization (EBITDA), as defined in the credit agreement, of 5.0 or less. As of December 31, 2012, this ratio was 3.7. Adjusted EBITDA is a non-GAAP measure. Because Adjusted EBITDA excludes some, but not all, items that affect net income and is defined differently by companies in our industry, Spectra Energy Partners definition of Adjusted EBITDA may not be comparable to similarly titled measures of other companies. Adjusted EBITDA should not be considered an alternative to net income, operating income, cash from operations or any other measure of financial performance or liquidity presented in accordance with GAAP.

The issuances of commercial paper, letters of credit and revolving borrowings reduce the amounts available under the credit facilities. As of December 31, 2012, there were no revolving borrowings outstanding.

Our credit agreement contains various covenants, including the maintenance of certain financial ratios. Failure to meet those covenants beyond applicable grace periods could result in accelerated due dates and/or termination of the agreements. As of December 31, 2012, we were in compliance with those covenants. In addition, our credit agreements allow for acceleration of payments or termination of the agreements due to nonpayment, or in some cases, due to the acceleration of other significant indebtedness of the borrower or some of its subsidiaries. Our debt and credit agreements do not contain provisions that trigger an acceleration of indebtedness based solely on the occurrence of a material adverse change in our financial condition or results of operations.

As noted above, the terms of our Spectra Capital credit agreement requires our consolidated debt-to-total capitalization ratio, as defined in the agreement, to be 65% or lower. Per the terms of the agreement, collateralized debt and Spectra Energy Partners debt and capitalization are excluded in the calculation of the ratio. This ratio was 58% at December 31, 2012. Approximately $6.2 billion of our equity (net assets) was considered restricted at December 31, 2012, representing the minimum amount of equity required to maintain the 65% consolidated debt-to-total capitalization ratio.

Delayed-draw Term Loan Agreement. On December 26, 2012, Spectra Capital entered into a three-year $1.2 billion unsecured delayed-draw term loan agreement which allows for up to four borrowings prior to March 1, 2013. Proceeds from borrowings under the term loan may be used for general corporate purposes, including acquisitions and to refinance existing indebtedness. As of December 31, 2012, we had no borrowings under the term loan.

16. Preferred Stock of Subsidiaries

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

At December 31, 2012, approximately 63% of the outstanding preferred shares were redeemable at the option of Westcoast and Union, as applicable.

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17. Fair Value Measurements

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

Description	Consolidated Balance Sheet Caption	December 31, 2012 Total	Level 1	Level 2	Level 3
		(in millions)			
Corporate debt securities	Cash and cash equivalents	$ 52	$	$ 52	$
Corporate debt securities	Current assets other	16		16	
Derivative assets interest rate swaps	Current assets other	13		13	
Corporate debt securities	Investments and other assets other	148		148	
Derivative assets interest rate swaps	Investments and other assets other	48		48	
Money market funds	Investments and other assets other	1	1		
Total Assets		$ 278	$ 1	$ 277	$
Derivative liabilities natural gas purchase contracts	Deferred credits and other liabilities regulatory and other	$ 9	$	$	$ 9
Derivative liabilities interest rate swaps	Deferred credits and other liabilities regulatory and other	12		12	
Total Liabilities		$ 21	$	$ 12	$ 9

Description	Consolidated Balance Sheet Caption	December 31, 2011 Total	Level 1	Level 2	Level 3
		(in millions)			
Corporate debt securities	Cash and cash equivalents	$ 49	$	$ 49	$
Canadian government securities	Current assets other	14	14		
Corporate debt securities	Current assets other	2		2	
Corporate debt securities	Investments and other assets other	16		16	
Derivative assets interest rate swaps	Investments and other assets other	66		66	
Money market funds	Investments and other assets other	3	3		
Total Assets		$ 150	$ 17	$ 133	$
Derivative liabilities natural gas purchase contracts	Current liabilities other	$ 1	$	$	$ 1
Derivative liabilities natural gas purchase contracts	Deferred credits and other liabilities regulatory and other	13			13
Derivative liabilities interest rate swaps	Deferred credits and other liabilities regulatory and other	16		16	
Total Liabilities		$ 30	$	$ 16	$ 14

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The following presents changes in Level 3 assets and liabilities that are measured at fair value on a recurring basis using significant unobservable inputs:

	2012	2011
	(in millions)	
Long-term derivative liabilities		
Fair value, beginning of period	$ 14	$ 6
Total realized/unrealized losses (gains):		
Included in earnings	3	3
Included in other comprehensive income	(7)	5
Settlements	(1)	
Fair value, end of period	$ 9	$ 14
Total losses for the period included in earnings (or changes in net assets) attributable to the change in unrealized gains or losses relating to liabilities held at the end of the period	$ 2	$ 3

Level 1

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

Level 2 Valuation Techniques

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

For interest rate swaps, we utilize data obtained from a third-party source for the determination of fair value. Both the future cash flows for the fixed-leg and floating-leg of our swaps are discounted to present value. In addition, credit default swap rates are used to develop the adjustment for credit risk embedded in our positions. We believe that since some of the inputs and assumptions for the calculations of fair value are derived from observable market data, a Level 2 classification is appropriate.

Level 3 Valuation Techniques

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

Financial Instruments

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

	December 31,			
	2012		2011	
	Book Value	Approximate Fair Value	Book Value	Approximate Fair Value
	(in millions)			
Notes receivable, noncurrent (a)	$ 71	$ 71	$ 71	$ 71

Long-term debt, including current maturities (b)	11,518	13,539	10,600	12,398

(a) Included within Investments in and Loans to Unconsolidated Affiliates.
(b) Excludes unamortized items and fair value hedge carrying value adjustments.

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The fair value of our long-term debt is determined based on market-based prices as described in the Level 2 valuation technique described above.

The fair values of cash and cash equivalents, restricted cash, short-term investments, accounts receivable, notes receivable-noncurrent, accounts payable and commercial paper are not materially different from their carrying amounts because of the short-term nature of these instruments or because the stated rates approximate market rates.

During 2012 and 2011, there were no material adjustments to assets and liabilities measured at fair value on a nonrecurring basis.

18. Risk Management and Hedging Activities

We are exposed to the impact of market fluctuations in the prices of NGLs and natural gas purchased as a result of our investment in DCP Midstream, and the ownership of the NGL marketing operations in western Canada and the processing plants associated with our U.S. pipeline assets. Exposure to interest rate risk exists as a result of the issuance of variable and fixed-rate debt and commercial paper. We are exposed to foreign currency risk from our Canadian operations. We employ established policies and procedures to manage our risks associated with these market fluctuations, which may include the use of derivatives, primarily around interest rate exposures.

DCP Midstream manages their direct exposure to market prices separate from Spectra Energy, and utilizes various risk management strategies, including the use of commodity derivatives.

Derivative Portfolio Carrying Value as of December 31, 2012

Asset/(Liability)	Maturity in 2013	Maturity in 2014	Maturity in 2015	Maturity in 2016 and Thereafter	Total Carrying Value
			(in millions)		
Hedging	$ 8	$ 12	$ 5	$ 27	$ 52
Undesignated		(12)			(12)
Total	$ 8	$	$ 5	$ 27	$ 40

These amounts represent the combination of amounts presented as assets (liabilities) for unrealized gains and losses on mark-to-market and hedging transactions on our Consolidated Balance Sheet and do not include any derivative positions of DCP Midstream. See Note 17 for information regarding the presentation of these derivative positions on our Consolidated Balance Sheets.

Accumulated unrealized mark-to-market net losses on hedges included in AOCI on the Consolidated Balance Sheet totaled $30 million as of December 31, 2012.

Commodity Cash Flow Hedges. Our NGL marketing operations are exposed to market fluctuations in the prices of natural gas and NGLs related to natural gas processing and marketing activities. We closely monitor the potential effects of commodity price changes and may choose to enter into contracts to protect margins for a portion of future sales and fuel expenses by using financial commodity instruments, such as swaps, forward contracts and options. There were no significant commodity cash flow hedge transactions during 2012, 2011 or 2010. We continue to evaluate various alternatives to address market uncertainties due to commodity price volatility.

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Interest Rate Hedges. Changes in interest rates expose us to risk as a result of our issuance of variable and fixed-rate debt and commercial paper. We manage our interest rate exposure by limiting our variable-rate exposures to percentages of total debt and by monitoring the effects of market changes in interest rates. We also enter into financial derivative instruments, including, but not limited to, interest rate swaps and rate lock agreements to manage and mitigate interest rate risk exposure.

For interest rate derivative instruments that are designated and qualify as fair value hedges, the gain or loss on the derivative as well as the offsetting loss or gain on the hedged item attributable to the hedged risk is recognized in the Consolidated Statements of Operations. There were no material amounts of gains or losses, either effective or ineffective, recognized in net income or other comprehensive income in 2012, 2011 or 2010.

At December 31, 2012, we had pay floating receive fixed interest rate swaps outstanding with a total notional principal amount of $2,102 million to hedge against changes in the fair value of our fixed-rate debt that arise as a result of changes in market interest rates. These swaps also allow us to transform a portion of the underlying interest payments related to our long-term fixed-rate debt securities into variable-rate interest payments in order to achieve our desired mix of fixed and variable-rate debt.

As of December 31, 2012, we had interest rate swaps with one counterparty which were in a net liability position of $6 million which could be terminated at any time. In addition, we had interest rate swaps with another counterparty which were in a net liability position of $6 million which could be terminated by the counterparty if one of our credit ratings falls below investment grade.

Foreign Currency Risk. We are exposed to foreign currency risk from investments and operations in Canada. To mitigate risks associated with foreign currency fluctuations, contracts may be denominated in or indexed to the U.S. dollar and/or local inflation rates, or investments may be naturally hedged through debt denominated or issued in the foreign currency. To monitor our currency exchange rate risks, we use sensitivity analysis, which measures the effect of devaluation of the Canadian dollar.

Credit Risk. Our principal customers for natural gas transportation, storage and gathering and processing services are industrial end-users, marketers, exploration and production companies, local distribution companies and utilities located throughout the United States and Canada. We have concentrations of receivables from natural gas utilities and their affiliates, industrial customers and marketers throughout these regions, as well as retail distribution customers in Canada. These concentrations of customers may affect our overall credit risk in that risk factors can negatively affect the credit quality of the entire sector. Where exposed to credit risk, we analyze the customers financial condition prior to entering into an agreement, establish credit limits and monitor the appropriateness of those limits on an ongoing basis. We also obtain parental guarantees, cash deposits or letters of credit from customers to provide credit support, where appropriate, based on our financial analysis of the customer and the regulatory or contractual terms and conditions applicable to each contract.

Included in Current Liabilities Other and Deferred Credits and Other Liabilities Regulatory and Other are collateral liabilities of $56 million at December 31, 2012 and $66 million at December 31, 2011, which represent cash collateral posted by third parties with us.

19. Commitments and Contingencies

General Insurance

We carry, either directly or through our captive insurance companies, insurance coverages consistent with companies engaged in similar commercial operations with similar type properties. Our insurance program includes (1) commercial general and excess liability insurance for liabilities to third parties for bodily injury and property damage resulting from our operations; (2) workers compensation liability coverage to required statutory limits; (3) automobile liability insurance for all owned, non-owned and hired vehicles covering liabilities to third parties for bodily injury and property damage; (4) insurance policies in support of the

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indemnification provisions of our by-laws; and (5) property insurance, including machinery breakdown, on an all-risk-replacement valued basis, onshore business interruption and extra expense. All coverages are subject to certain deductibles, terms and conditions common for companies with similar types of operations.

Environmental

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

Like others in the energy industry, we and our affiliates are responsible for environmental remediation at various contaminated sites. These include some properties that are part of our ongoing operations, sites formerly owned or used by us, and sites owned by third parties. Remediation typically involves management of contaminated soils and may involve groundwater remediation. Managed in conjunction with relevant federal, state/provincial and local agencies, activities vary with site conditions and locations, remedial requirements, complexity and sharing of responsibility. If remediation activities involve statutory joint and several liability provisions, strict liability, or cost recovery or contribution actions, we or our affiliates could potentially be held responsible for contamination caused by other parties. In some instances, we may share liability associated with contamination with other potentially responsible parties, and may also benefit from insurance policies or contractual indemnities that cover some or all cleanup costs. All of these sites generally are managed in the normal course of business or affiliated operations.

Included in Deferred Credits and Other Liabilities Regulatory and Other on the Consolidated Balance Sheets are undiscounted liabilities related to extended environmental-related activities totaling $13 million as of December 31, 2012 and $16 million as of December 31, 2011. These liabilities represent provisions for costs associated with remediation activities at some of our current and former sites, as well as other environmental contingent liabilities.

Litigation

Litigation and Legal Proceedings. We are involved in legal, tax and regulatory proceedings in various forums arising in the ordinary course of business, including matters regarding contract and payment claims, some of which involve substantial monetary amounts. We have insurance coverage for certain of these losses should they be incurred. We believe that the final disposition of these proceedings will not have a material effect on our consolidated results of operations, financial position or cash flows.

Legal costs related to the defense of loss contingencies are expensed as incurred. We had no material reserves recorded as of December 31, 2012 or 2011 related to litigation.

Other Commitments and Contingencies

See Note 20 for a discussion of guarantees and indemnifications.

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Operating Lease Commitments

We lease assets in various areas of our operations. Consolidated rental expense for operating leases classified in Income From Continuing Operations was $38 million in 2012, $39 million in 2011 and $49 million in 2010, which is included in Operating, Maintenance and Other on the Consolidated Statements of Operations. The following is a summary of future minimum lease payments under operating leases which at inception had noncancelable terms of more than one year. We had no material capital lease commitments at December 31, 2012.

	Long-term Operating Leases (in millions)
2013	$ 60
2014	58
2015	44
2016	35
2017	29
Thereafter	151
Total future minimum lease payments	$ 377

20. Guarantees and Indemnifications

We have various financial guarantees and indemnifications which are issued in the normal course of business. As discussed below, these contracts include financial guarantees, stand-by letters of credit, debt guarantees, surety bonds and indemnifications. We enter into these arrangements to facilitate a commercial transaction with a third party by enhancing the value of the transaction to the third party. To varying degrees, these guarantees involve elements of performance and credit risk, which are not included on our Consolidated Balance Sheets. The possibility of having to perform under these guarantees and indemnifications is largely dependent upon future operations of various subsidiaries, investees and other third parties, or the occurrence of certain future events.

We have issued performance guarantees to customers and other third parties that guarantee the payment and performance of other parties, including certain non-100%-owned entities. In connection with our spin-off from Duke Energy in 2007, certain guarantees that were previously issued by us were assigned to, or replaced by, Duke Energy as guarantor in 2006. For any remaining guarantees of other Duke Energy obligations, Duke Energy has indemnified us against any losses incurred under these guarantee arrangements. The maximum potential amount of future payments we could have been required to make under these performance guarantees as of December 31, 2012 was approximately $406 million, which has been indemnified by Duke Energy as discussed above. One of these outstanding performance guarantees, which has a maximum potential amount of future payment of $201 million, expires in 2028. The remaining guarantees have no contractual expirations.

We have also issued joint and several guarantees to some of the Duke/Fluor Daniel (D/FD) project owners, guaranteeing the performance of D/FD under its engineering, procurement and construction contracts and other contractual commitments in place at the time of our spin-off from Duke Energy. D/FD is one of the entities transferred to Duke Energy in connection with our spin-off. Substantially all of these guarantees have no contractual expiration and no stated maximum amount of future payments that we could be required to make. Fluor Enterprises Inc., as 50% owner in D/FD, issued similar joint and several guarantees to the same D/FD project owners.

Westcoast, a 100%-owned subsidiary, has issued performance guarantees to third parties guaranteeing the performance of unconsolidated entities, such as equity method investments, and of entities previously sold by Westcoast to third parties. Those guarantees require Westcoast to make payment to the guaranteed third party

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upon the failure of such unconsolidated or sold entity to make payment under some of its contractual obligations, such as debt agreements, purchase contracts and leases. Certain guarantees that were previously issued by Westcoast for obligations of entities that remained a part of Duke Energy are considered guarantees of third party performance; however, Duke Energy has indemnified us against any losses incurred under these guarantee arrangements.

We have entered into various indemnification agreements related to purchase and sale agreements and other types of contractual agreements with vendors and other third parties. These agreements typically cover environmental, litigation and other matters, as well as breaches of representations, warranties and covenants. Typically, claims may be made by third parties for various periods of time depending on the nature of the claim. Our potential exposure under these indemnification agreements can range from a specified amount, such as the purchase price, to an unlimited dollar amount, depending on the nature of the claim and the particular transaction. We are unable to estimate the total potential amount of future payments under these indemnification agreements due to several factors, such as the unlimited exposure under certain guarantees.

As of December 31, 2012, the amounts recorded for the guarantees and indemnifications described above are not material, both individually and in the aggregate. See also Note 6 for discussion of indemnifications to Duke Energy of certain income tax liabilities.

21. Common Stock Issuance

On December 17, 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.

22. Effects of Changes in Noncontrolling Interests Ownership

The following table presents the effects of changes in our ownership interests in non-100%-owned consolidated subsidiaries:

	2012	2011 (in millions)	2010
Net Income Controlling Interests	$ 940	$ 1,184	$ 1,049
Increase in Additional Paid-in Capital resulting from sales of units of Spectra Energy Partners (a)	26	38	50
Total Net Income Controlling Interests and changes in Equity Controlling Interests	$ 966	$ 1,222	$ 1,099

(a) See Note 2 for further discussion.

23. Stock-Based Compensation

The Spectra Energy Corp 2007 Long-Term Incentive Plan (the 2007 LTIP), as amended and restated, provides for the granting of restricted stock awards and units, unrestricted stock awards and units, stock options and other equity-based awards, to employees and other key individuals who perform services for us. A maximum of 40 million shares of common stock may be awarded under the 2007 LTIP.

Restricted, performance and phantom stock awards granted under the 2007 LTIP typically become 100% vested on the three-year anniversary of the grant date. Equity-classified and liability-classified stock-based compensation cost is measured at the grant date based on the fair value of the award. Liability-classified stock-based compensation cost is re-measured at each reporting period until settlement. Related compensation expense is recognized over the requisite service period, which is the same as the vesting period.

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Options granted under the 2007 LTIP are issued with exercise prices equal to the fair market value of our common stock on the grant date, have ten year terms and generally vest over a three-year term. Compensation expense related to stock options is recognized over the requisite service period. The requisite service period for stock options is the same as the vesting period, with the exception of retirement eligible employees, who have shorter requisite service periods ending when the employees become retirement eligible. We issue new shares upon exercising or vesting of share-based awards. The Black-Scholes option-pricing model is used to estimate the fair value of options at grant date.

At the time of our spin-off from Duke Energy, Duke Energy converted stock options, restricted stock awards, performance awards and phantom stock awards (collectively, Stock-Based Awards) of Duke Energy common stock held by our employees and Duke Energy employees. One replacement Duke Energy Stock-Based Award and one-half Spectra Energy Stock-Based Award were distributed to each holder of Duke Energy Stock-Based Awards for each award held at the time of the spin-off. The Spectra Energy Stock-Based Awards resulting from the conversion are considered to have been issued under the 2007 LTIP.

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

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

	2012	2011	2010
		(in millions)	
Phantom stock	$ 12	$ 12	$ 13
Performance awards	17	17	13
Total	$ 29	$ 29	$ 26

The tax benefit recognized in Income From Continuing Operations associated with stock-based compensation expense was $8 million in 2012, $7 million in 2011 and $4 million in 2010. We recognized tax benefits from stock-based compensation cost of approximately $16 million in 2012, $3 million in 2011 and $2 million in 2010 in Additional Paid-in Capital.

Stock Awards Activity

	Performance Awards		Phantom Stock Awards	
	Units	Weighted Average Grant Date Fair Value	Units	Weighted Average Grant Date Fair Value
	(units in thousands)			
Outstanding at December 31, 2011	2,095	$ 25	1,856	$ 19
Granted	614	28	440	31
Vested	(797)	15	(777)	14
Forfeited	(24)	30	(44)	24
Outstanding at December 31, 2012	1,888	28	1,475	25
Awards expected to vest	1,871	28	1,431	25

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Performance Awards

Under the 2007 LTIP, we can also grant stock-based and cash-based performance awards. The performance awards generally vest over three years at the earliest, if performance metrics are met. The cash-based awards will be settled in cash at vesting. We granted 306,800 stock-based awards during 2012, 364,600 during 2011 and 624,100 during 2010, with fair values of $13 million in 2012, $12 million in 2011 and $19 million in 2010. We granted 306,800 cash-based awards during 2012, 339,200 during 2011 and none during 2010, with fair values of $5 million in 2012 and $10 million in 2011. The unvested and outstanding performance awards granted contain market conditions based on the total shareholder return of Spectra Energy common stock relative to a pre-defined peer group. The stock-based and cash-based awards are valued using the Monte Carlo valuation method. The cash-based awards are remeasured at each reporting period until settlement.

Weighted-Average Assumptions for Stock-Based Performance Awards

	2012	2011	2010
Risk-free rate of return	0.4%	1.2%	1.4%
Expected life	3 years	3 years	3 years
Expected volatility Spectra Energy	25%	38%	38%
Expected volatility peer group	16% 42%	21% 60%	22% 59%
Market index	20%	30%	30%

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

The total fair value of the shares vested in 2012 was $12 million, $12 million in 2011 and none in 2010 as Spectra Energy performance awards were first granted in 2008. As of December 31, 2012, we expect to recognize $20 million of future compensation cost related to outstanding performance awards over a weighted-average period of less than two years.

Phantom Stock Awards

Stock-based phantom awards granted under the 2007 LTIP generally vest over three years. We awarded 440,200 phantom awards to our employees in 2012, 453,000 awards in 2011 and 655,100 awards in 2010, with fair values of $14 million in 2012, $12 million in 2011 and $14 million in 2010.

The total fair value of the shares vested in 2012 was $11 million, $13 million in 2011 and $12 million in 2010. As of December 31, 2012, we expect to recognize $15 million of future compensation cost related to phantom stock awards over a weighted-average period of less than two years.

Stock Option Activity

	Options (in thousands)	Weighted-Average Exercise Price	Weighted-Average Remaining Life (in years)	Aggregate Intrinsic Value (in millions)
Outstanding at December 31, 2011	4,891	$ 24	3.3	$ 36
Exercised	(925)	18		
Forfeited or expired	(488)	33		
Outstanding at December 31, 2012	3,478	24	3.1	13
Exercisable at December 31, 2012	3,478	24	3.1	13

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We did not award any non-qualified stock options to employees during 2012, 2011 or 2010.

Coincident with our spin-off, all exercisable Duke Energy options were converted in accordance with the share conversion guidelines on a two-to-one basis, with no change to overall intrinsic value. The total intrinsic value of options exercised was $11 million in 2012, $14 million in 2011 and 6 million in 2010. Cash received by us from options exercised was $17 million in 2012, $32 million in 2011 and $13 million in 2010. We recognized a nominal tax benefit in 2010 since the options exercised were predominately held by Duke Energy employees. All stock options were fully vested as of December 31, 2011, and as a result, we do not expect to recognize future compensation costs related to stock options.

24. Employee Benefit Plans

Retirement Plans. We have a qualified non-contributory defined benefit (DB) retirement plan for U.S. employees (U.S. Qualified Pension Plan). This plan covers U.S. employees using a cash balance formula. Under a cash balance formula, a plan participant accumulates a retirement benefit consisting of pay credits that are based upon a percentage (which may vary with age and years of service) of current eligible earnings and current interest credits.

We also maintain non-qualified, non-contributory, unfunded defined benefit plans (U.S. Non-Qualified Pension Plans) which cover certain current and former U.S. executives. The U.S. Non-Qualified Pension Plans have no plan assets. There are other non-qualified plans such as savings and deferred compensation plans which cover certain current and former U.S. executives. Pursuant to trust agreements, Spectra Energy has set aside funds for certain of the above non-qualified plans in several trusts. Although these funds are restrictive in nature, they remain a component of our general assets and are subject to the claims of creditors. These trust funds of $17 million as of December 31, 2012 and $22 million as of December 31, 2011, invested in money market funds and valued using a Level 1 hierarchy level, are considered AFS securities and are classified as Investments and Other Assets-Other on the Consolidated Balance Sheets.

In addition, our Westcoast subsidiary maintains qualified and non-qualified, contributory and non-contributory (Canadian Qualified Pension Plan) and (Canadian Non-Qualified Pension Plan) DB and defined contribution (Canadian DC) retirement plans covering substantially all employees of our Canadian operations. The DB plans provide retirement benefits based on each plan participant s years of service and final average earnings. Under the DC plan, company contributions are determined according to the terms of the plan and based on each plan participant s age, years of service and current eligible earnings. We also provide non-qualified DB supplemental pensions to all employees who retire under a DB qualified pension plan and whose pension is limited by the maximum pension limits under the Income Tax Act (Canada). We report our Canadian benefit plans separate from the U.S. plans due to differences in actuarial assumptions.

Our policy is to fund our retirement plans, where applicable, on an actuarial basis to provide assets sufficient to meet benefits to be paid to plan participants or as required by legislation or plan terms. We made contributions of $26 million to our U.S. Qualified and Non-Qualified Pension Plans in 2012, $21 million in 2011 and $31 million in 2010. We made total contributions to our Canadian Qualified and Non-Qualified Pension Plans of $87 million in 2012, $144 million in 2011 and $67 million in 2010. Contributions of $9 million in 2012, $8 million in 2011 and $7 million in 2010 were made to our Canadian DC plan. We anticipate that in 2013 we will make total contributions of approximately $20 million to the U.S. Qualified and Non-Qualified Pension Plans, approximately $90 million to the Canadian Qualified and Non-Qualified Pension Plans and approximately $10 million to the Canadian DC Plan.

Actuarial gains and losses are amortized over the average remaining service period of active employees. The average remaining service period of active employees covered by the U.S. Qualified and Non-Qualified Pension Plans is 10 years. The average remaining service periods of active employees covered by the Canadian Qualified and Non-Qualified Pension Plans are 10 years and 14 years, respectively. We determine the market-related value of plan assets using a calculated value that recognizes changes in fair value of the plan assets over five years for the U.S. plans and over three years for the Canadian plans.

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Qualified and Non-Qualified Pension Plans

Change in Projected Benefit Obligation and Change in Fair Value of Plan Assets

	U.S.		Canada	
	2012	2011	2012	2011
	(in millions)			
Change in Projected Benefit Obligation				
Projected benefit obligation, beginning of period	$ 557	$ 528	$ 1,156	$ 1,005
Service cost	17	13	30	20
Interest cost	23	25	50	53
Actuarial loss	50	30	37	149
Participant contributions			5	5
Benefits paid	(37)	(39)	(50)	(48)
Prior service cost				1
Foreign currency translation effect			34	(29)
Projected benefit obligation, end of period	610	557	1,262	1,156
Change in Fair Value of Plan Assets				
Plan assets, beginning of period	443	447	840	754
Actual return on plan assets	51	14	55	2
Benefits paid	(37)	(39)	(50)	(48)
Employer contributions	26	21	87	144
Plan participants contributions			5	5
Foreign currency translation effect			24	(17)
Plan assets, end of period	483	443	961	840
Net amount recognized (a)	$ (127)	$ (114)	$ (301)	$ (316)
Accumulated Benefit Obligation	$ 575	$ 529	$ 1,176	$ 1,074

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

The U.S. and Canadian Qualified and Non-Qualified Pension Plans had accumulated benefit obligations in excess of plan assets.

Amounts Recognized in Accumulated Other Comprehensive Income

	U.S.		Canada	
	December 31,		December 31,	
	2012	2011	2012	2011
	(in millions)			
Net actuarial loss	$ 234	$ 216	$ 443	$ 435
Prior service costs	1	1	9	11
Total amount recognized in AOCI	$ 235	$ 217	$ 452	$ 446

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Components of Net Periodic Pension Costs

	U.S.			Canada		
	2012	2011	2010	2012	2011	2010
	(in millions)					
Net Periodic Pension Cost						
Service cost benefit earned	$ 17	$ 13	$ 12	$ 30	$ 20	$ 17
Interest cost on projected benefit obligation	23	25	26	50	53	51
Expected return on plan assets	(33)	(32)	(31)	(61)	(49)	(45)
Amortization of prior service cost				2	2	2
Amortization of loss	15	11	8	36	27	18
Net periodic pension cost	22	17	15	57	53	43
Other Changes in Plan Assets and Benefit Obligations Recognized in Other Comprehensive Income						
Current year actuarial loss	33	48	7	44	184	28
Amortization of actuarial loss	(15)	(11)	(8)	(36)	(27)	(18)
Amortization of prior service credit				(2)	(2)	(2)
Current year prior service cost					1	
Total recognized in other comprehensive income	18	37	(1)	6	156	8
Total Recognized in Net Periodic Pension Cost and Other Comprehensive Income	$ 40	$ 54	$ 14	$ 63	$ 209	$ 51

At December 31, 2012, approximately $20 million of actuarial losses for the U.S. plans and $36 million for the Canadian plans will be amortized from AOCI on the Consolidated Balance Sheets into net periodic benefit cost in 2013.

At December 31, 2012, approximately $2 million of prior service costs will be amortized from AOCI into net periodic pension costs in 2013 for the Canadian plans.

Assumptions Used for Pension Benefits Accounting

	U.S.			Canada		
	2012	2011	2010	2012	2011	2010
Benefit Obligations						
Discount rate	3.55%	4.17%	4.82%	4.15%	4.30%	5.25%
Salary increase	4.61	4.61	4.68	3.25	3.25	3.25
Net Periodic Benefit Cost						
Discount rate	4.17	4.82	5.28	4.30	5.25	5.87
Salary increase	4.61	4.68	4.73	3.25	3.25	3.50
Expected long-term rate of return on plan assets	7.40	7.00	7.25	7.10	7.00	7.00

The discount rates used to determine the benefit obligations are the rates at which the benefit obligations could be effectively settled. The discount rates for our U.S. and Canadian plans are developed from yields on available high-quality bonds in each country and reflect each plan s expected cash flows.

The long-term rates of return for the U.S. and Canadian plan assets as of December 31, 2012 were developed using weighted-average calculations of expected returns based primarily on future expected returns across classes considering the use of active asset managers applied against the U.S. and Canadian plans respective targeted asset mix.

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Qualified Pension Plan Assets

	U.S.			Canada		
	Target	December 31,		Target	December 31,	
Asset Category	Allocation	2012	2011	Allocation	2012	2011
U.S. equity securities	28%	28%	34%	14%	14%	14%
Canadian equity securities				28	28	27
Other equity securities	12	13	13	13	13	13
Fixed income securities	45	45	47	45	45	46
Other investments	15	14	6			
Total	100%	100%	100%	100%	100%	100%

Pension plan assets are maintained in master trusts in both the U.S. and Canada. The investment objective of the master trusts is to achieve reasonable returns on trust assets, subject to a prudent level of portfolio risk, for the purpose of enhancing the security of benefits for plan participants. The asset allocation targets were set after considering the investment objective and the risk profile with respect to the trusts. Equities are held for their high expected return. Other equity and fixed income securities are held for diversification. Investments within asset classes are diversified to achieve broad market participation and reduce the effects of individual managers or investments. We regularly review our actual asset allocation and periodically rebalance our investments to the targeted allocation when considered appropriate.

The following table summarizes the fair values of pension plan assets recorded at each fair value hierarchy level, as determined in accordance with the valuation techniques described in Note 17:

	U.S.				Canada			
	Total	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3
				(in millions)				
December 31, 2012								
Cash and cash equivalents	$	$	$	$	$ 5	$ 5	$	$
Fixed income securities	217	217			434	420	14	
Equity securities	197	197			521	377	144	
Other	69			69	1			1
Total	$ 483	$ 414	$	$ 69	$ 961	$ 802	$ 158	$ 1
December 31, 2011								
Cash and cash equivalents	$	$	$	$	$ 5	$ 5	$	$
Fixed income securities	211	211			380	365	15	
Equity securities	208	208			452	323	129	
Other	24			24	3			3
Total	$ 443	$ 419	$	$ 24	$ 840	$ 693	$ 144	$ 3

The following presents changes in Level 3 assets that are measured at fair value on a recurring basis using significant unobservable inputs:

	U.S.		Canada	
	2012	2011	2012	2011
		(in millions)		
Fair value, beginning of period	$ 24	$ 24	$ 3	$ 3
Purchases	40			
Unrealized gain (loss) included in other comprehensive income	5		(2)	

Fair value, end of period	$ 69	$ 24	$ 1	$ 3

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Expected Benefit Payments

	U.S.	Canada
	(in millions)	
2013	$ 48	$ 53
2014	48	56
2015	51	58
2016	52	61
2017	52	63
2018 2022	263	278

Other Post-Retirement Benefit Plans

U.S. Other Post-Retirement Benefits. We provide certain health care and life insurance benefits for retired employees on a contributory and non-contributory basis. Employees are eligible for these benefits if they have met age and service requirements at retirement, as defined in the plans.

These benefit costs are accrued over an employee s active service period to the date of full benefits eligibility. Actuarial gains and losses are amortized over the average remaining service period of the active employees of 12 years. We determine the market-related value of the plan assets using a calculated value that recognizes changes in fair value of the plan assets over five years for the U.S. plans.

Canadian Other Post-Retirement Benefits. We provide health care and life insurance benefits for retired employees on a non-contributory basis for our Canadian operations predominantly under defined contribution plans. Employees are eligible for these benefits if they have met age and service requirements at retirement, as defined in the plans. The Canadian plans are not funded.

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

	U.S.		Canada	
	2012	2011	2012	2011
	(in millions)			
Change in Benefit Obligation				
Accumulated post-retirement benefit obligation, beginning of period	$ 200	$ 205	$ 161	$ 135
Service cost	1	1	7	5
Interest cost	8	10	7	7
Plan participants contribution	3	3		
Actuarial loss (gain)	7	(1)	(26)	23
Medicare subsidy receivable	3	3		
Benefits paid	(20)	(20)	(5)	(5)
Plan amendments		(1)		
Foreign currency translation effect			5	(4)
Accumulated post-retirement benefit obligation, end of period	202	200	149	161
Change in Fair Value of Plan Assets				
Plan assets, beginning of period	76	78		
Actual return on plan assets	7	2		
Benefits paid	(20)	(20)	(5)	(5)
Employer contributions	13	13	5	5
Plan participants contributions	3	3		
Plan assets, end of period	79	76		
Net amount recognized (a)	$ (123)	$ (124)	$ (149)	$ (161)

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

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

	U.S. December 31,		Canada December 31,	
	2012	2011	2012	2011
	(in millions)			
Prior service credit	$	$	$ (6)	$ (7)
Net actuarial loss	26	22	19	47
Total amount recognized in AOCI	$ 26	$ 22	$ 13	$ 40

As of December 31, 2012, approximately $2 million of actuarial losses were included in AOCI in the Consolidated Balance Sheet that will be amortized into net periodic benefit costs in 2013 for the U.S. plan. As of December 31, 2012, approximately $1 million of prior service costs will be amortized into net periodic benefit cost from AOCI in 2013 for the Canadian plans.

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	U.S. 2012	U.S. 2011	U.S. 2010	Canada 2012	Canada 2011	Canada 2010
			(in millions)			
Other Post-Retirement Benefit Plans Components of Net Periodic Benefit Cost						
Service cost benefit earned	$ 1	$ 1	$ 1	$ 7	$ 5	$ 3
Interest cost on accumulated post-retirement benefit obligation	8	10	11	7	7	7
Expected return on plan assets	(5)	(5)	(5)			
Amortization of net transition obligation			4			
Amortization of prior service credit				(1)	(1)	(1)
Amortization of loss	2	2	1	2	1	1
Net periodic other post-retirement benefit cost	6	8	12	15	12	10
Other Changes in Plan Assets and Benefit Obligations Recognized in Other Comprehensive Income						
Current year actuarial loss (gain)	6	1	1	(26)	26	13
Amortization of actuarial loss	(2)	(2)	(1)	(2)	(1)	(1)
Current year prior service credit		(1)	(6)			
Amortization of prior service credit				1	1	1
Amortization of net transition obligation			(4)			
Total recognized in other comprehensive income	4	(2)	(10)	(27)	26	13
Total recognized in net periodic benefit cost and other comprehensive income	$ 10	$ 6	$ 2	$ (12)	$ 38	$ 23

Other Post-Retirement Benefits Plans Assumptions Used for Benefits Accounting

	U.S. 2012	U.S. 2011	U.S. 2010	Canada 2012	Canada 2011	Canada 2010
Benefit Obligations						
Discount rate	3.70%	4.31%	4.93%	4.20%	4.33%	5.31%
Salary increase	4.61	4.61	4.68	3.25	3.25	3.25
Net Periodic Benefit Cost						
Discount rate	4.31	4.93	5.37	4.33	5.31	5.95
Salary increase	4.61	4.68	4.73	3.25	3.25	3.50
Expected return on plan assets	6.54	6.26	6.51	n/a	n/a	n/a

n/a Indicates not applicable.

The discount rates used to determine the post-retirement obligations are the rates at which the benefit obligations could be effectively settled. The discount rates for our U.S. and Canadian plans are developed from yields on available high-quality bonds in each country and reflect each plan s expected cash flows.

Assumed Health Care Cost Trend Rates

	U.S. 2012	U.S. 2011	Canada 2012	Canada 2011
Health care cost trend rate assumed for next year	7.50%	8.00%	7.00%	7.50%
Rate to which the cost trend is assumed to decline	5.00%	5.00%	5.00%	5.00%
Year that the rate reaches the ultimate trend rate	2018	2018	2017	2017

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Sensitivity to Changes in Assumed Health Care Cost Trend Rates

	U.S.		Canada	
	1% Point Increase	1% Point Decrease	1% Point Increase	1% Point Decrease
	(in millions)			
Effect on total service and interest costs	$	$	$ 1	$ (1)
Effect on post-retirement benefit obligations	8	(7)	9	(8)

Other Post-Retirement Plan Assets

Asset Category	U.S. December 31, 2012	2011
Cash and cash equivalents	1%	%
Equity securities	44	45
Fixed income securities	48	52
Other assets	7	3
Total	100%	100%

A portion of our other post-retirement plan assets is maintained within the U.S. master trust discussed under the pension plans above. We invest other post-retirement plan assets in the Spectra Energy Corp Employee Benefits Trust (VEBA I) and the Spectra Energy Corp Post-Retirement Medical Benefits Trust (VEBA II). The investment objective of the VEBAs is to achieve sufficient returns on trust assets, subject to a prudent level of portfolio risk, for the purpose of promoting the security of plan benefits for participants. The VEBA trusts are passively managed.

The asset allocation table above includes the other post-retirement benefit assets held in the master trusts, VEBA I and VEBA II.

The following table summarizes the fair values of the other post-retirement plan assets recorded at each fair value hierarchy level as determined in accordance with the valuation techniques described in Note 17:

	U.S.							
	VEBA I and VEBA II Trusts				Master Trust			
	Total	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3
	(in millions)							
December 31, 2012								
Cash and cash equivalents	$ 1	$	$ 1	$	$	$	$	$
Fixed income securities	21		21		17	17		
Equity securities	19		19		16	16		
Other investments					5			5
Total	$ 41	$	$ 41	$	$ 38	$ 33	$	$ 5
December 31, 2011								
Fixed income securities	$ 24	$	$ 24	$	$ 16	$ 16	$	$
Equity securities	18		18		16	16		
Other investments					2			2
Total	$ 42	$	$ 42	$	$ 34	$ 32	$	$ 2

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The following presents changes in Level 3 assets that are measured at fair value on a recurring basis using significant unobservable inputs:

	U.S. 2012	U.S. 2011
	(in millions)	
Fair value, beginning of period	$ 2	$ 2
Purchases	3	
Fair value, end of period	$ 5	$ 2

Other Post-Retirement Benefit Plans-Payments and Receipts

We expect to make future benefit payments, which reflect expected future service, as appropriate. As our plans provide benefits that are actuarially equivalent to the benefits received by Medicare recipients, we expect to receive future subsidies under Medicare Part D. The following benefit payments and subsidies are expected to be paid (or received) over each of the next five years and thereafter.

	Benefit Payments U.S.	Benefit Payments Canada	Medicare Part D Subsidy Receipts U.S.
		(in millions)	
2013	$ 17	$ 5	$ (2)
2014	17	5	(2)
2015	17	6	(3)
2016	17	6	(3)
2017	16	7	(3)
2018 2022	71	38	(13)

We anticipate making contributions in 2013 of $11 million to the U.S. plans and $5 million to the Canadian plans.

Retirement Savings Plan

We have employee savings plans available to both U.S. and Canadian employees. Employees may participate in a matching contribution where we match a certain percentage of before-tax employee contributions of up to 6% of eligible pay per pay period for U.S. employees and up to 5% of eligible pay per pay period for Canadian employees. We expensed pre-tax employer matching contributions of $12 million in each of 2012 and 2011, and $11 million 2010 for U.S employees, and $12 million in each of 2012 and 2011, and $11 million in 2010 for Canadian employees.

25. Consolidating Financial Information

Spectra Energy Corp has agreed to fully and unconditionally guarantee the payment of principal and interest under all series of notes outstanding under the Senior Indenture of Spectra Capital, a 100%-owned, consolidated subsidiary. In accordance with the Securities and Exchange Commission (SEC) rules, the following condensed consolidating financial information is presented. The information shown for Spectra Energy Corp and Spectra Capital is presented utilizing the equity method of accounting for investments in subsidiaries, as required. The non-guarantor subsidiaries column represents all consolidated subsidiaries of Spectra Capital. This information should be read in conjunction with our accompanying Consolidated Financial Statements and notes thereto.

Certain amounts in the condensed consolidating balance sheet and statements of cash flow for prior periods, primarily intercompany receivables, payables and advances, have been reclassified to conform to the current period presentation.

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Spectra Energy Corp

Condensed Consolidating Statement of Operations

Year Ended December 31, 2012

(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Total operating revenues	$	$	$ 5,077	$ (2)	$ 5,075
Total operating expenses	5	5	3,494	(2)	3,502
Gains on sales of other assets and other, net			2		2
Operating income (loss)	(5)	(5)	1,585		1,575
Equity in earnings of unconsolidated affiliates			382		382
Equity in earnings of subsidiaries	917	1,377		(2,294)	
Other income and expenses, net	(2)	3	82		83
Interest expense		190	435		625
Earnings from continuing operations before income taxes	910	1,185	1,614	(2,294)	1,415
Income tax expense (benefit) from continuing operations	(31)	268	133		370
Income from continuing operations	941	917	1,481	(2,294)	1,045
Income (loss) from discontinued operations, net of tax	(1)		3		2
Net income	940	917	1,484	(2,294)	1,047
Net income noncontrolling interests			107		107
Net income controlling interests	$ 940	$ 917	$ 1,377	$ (2,294)	$ 940

Spectra Energy Corp

Condensed Consolidating Statement of Operations

Year Ended December 31, 2011

(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Total operating revenues	$	$	$ 5,354	$ (3)	$ 5,351
Total operating expenses	1		3,598	(3)	3,596
Gains on sales of other assets and other, net			8		8
Operating income (loss)	(1)		1,764		1,763
Equity in earnings of unconsolidated affiliates			549		549
Equity in earnings of subsidiaries	1,183	1,666		(2,849)	

Other income and expenses, net		5	52		57
Interest expense		194	431		625
Earnings from continuing operations before income taxes	1,182	1,477	1,934	(2,849)	1,744
Income tax expense (benefit) from continuing operations	(6)	294	199		487
Income from continuing operations	1,188	1,183	1,735	(2,849)	1,257
Income (loss) from discontinued operations, net of tax	(4)		29		25
Net income	1,184	1,183	1,764	(2,849)	1,282
Net income noncontrolling interests			98		98
Net income controlling interests	$ 1,184	$ 1,183	$ 1,666	$ (2,849)	$ 1,184

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Spectra Energy Corp

Condensed Consolidating Statement of Operations

Year Ended December 31, 2010

(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Total operating revenues	$	$	$ 4,945	$	$ 4,945
Total operating expenses	15	2	3,264		3,281
Gains on sales of other assets and other, net			10		10
Operating income (loss)	(15)	(2)	1,691		1,674
Equity in earnings of unconsolidated affiliates			430		430
Equity in earnings of subsidiaries	1,062	1,492		(2,554)	
Other income and expenses, net		(4)	36		32
Interest expense		199	431		630
Earnings from continuing operations before income taxes	1,047	1,287	1,726	(2,554)	1,506
Income tax expense (benefit) from continuing operations	(2)	225	160		383
Income from continuing operations	1,049	1,062	1,566	(2,554)	1,123
Income from discontinued operations, net of tax			6		6
Net income	1,049	1,062	1,572	(2,554)	1,129
Net income noncontrolling interests			80		80
Net income controlling interests	$ 1,049	$ 1,062	$ 1,492	$ (2,554)	$ 1,049

Spectra Energy Corp

Condensed Consolidating Statements of Comprehensive Income

(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Year Ended December 31, 2012					
Net income	$ 940	$ 917	$ 1,484	$ (2,294)	$ 1,047
Other comprehensive income (loss)	(12)	3	248		239
Total comprehensive income, net of tax	928	920	1,732	(2,294)	1,286
Less: comprehensive income noncontrolling interests			110		110

Comprehensive income controlling interests	$ 928	$ 920	$ 1,622	$ (2,294)	$ 1,176
Year Ended December 31, 2011					
Net income	$ 1,184	$ 1,183	$ 1,764	$ (2,849)	$ 1,282
Other comprehensive income (loss)	(21)	2	(301)		(320)
Total comprehensive income, net of tax	1,163	1,185	1,463	(2,849)	962
Less: comprehensive income noncontrolling interests			100		100
Comprehensive income controlling interests	$ 1,163	$ 1,185	$ 1,363	$ (2,849)	$ 862
Year Ended December 31, 2010					
Net income	$ 1,049	$ 1,062	$ 1,572	$ (2,554)	$ 1,129
Other comprehensive income (loss)	7	(9)	312		310
Total comprehensive income, net of tax	1,056	1,053	1,884	(2,554)	1,439
Less: comprehensive income noncontrolling interests			96		96
Comprehensive income controlling interests	$ 1,056	$ 1,053	$ 1,788	$ (2,554)	$ 1,343

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Spectra Energy Corp

Condensed Consolidating Balance Sheet

December 31, 2012

(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Cash and cash equivalents	$	$ 3	$ 91	$	$ 94
Receivables consolidated subsidiaries	164			(164)	
Receivables other	1	56	913		970
Other current assets	17	23	559		599
Total current assets	182	82	1,563	(164)	1,663
Investments in and loans to unconsolidated affiliates		70	2,622		2,692
Investments in consolidated subsidiaries	12,974	14,969		(27,943)	
Advances receivable consolidated subsidiaries		5,658		(5,658)	
Notes receivable consolidated subsidiaries			912	(912)	
Goodwill			4,513		4,513
Other assets	39	67	466		572
Property, plant and equipment, net			19,905		19,905
Regulatory assets and deferred debits	3	14	1,225		1,242
Total Assets	$ 13,198	$ 20,860	$ 31,206	$ (34,677)	$ 30,587
Accounts payable other	$ 4	$ 74	$ 386	$	$ 464
Accounts payable consolidated subsidiaries		91	73	(164)	
Commercial paper		513	746		1,259
Short-term borrowings consolidated subsidiaries		912		(912)	
Accrued taxes payable	10		57		67
Current maturities of long-term debt		744	177		921
Other current liabilities	61	106	913		1,080
Total current liabilities	75	2,440	2,352	(1,076)	3,791
Long-term debt		2,550	8,103		10,653
Advances payable consolidated subsidiaries	3,957		1,701	(5,658)	
Deferred credits and other liabilities	194	2,896	2,952		6,042
Preferred stock of subsidiaries			258		258
Equity					
Controlling interests	8,972	12,974	14,969	(27,943)	8,972
Noncontrolling interests			871		871
Total equity	8,972	12,974	15,840	(27,943)	9,843
Total Liabilities and Equity	$ 13,198	$ 20,860	$ 31,206	$ (34,677)	$ 30,587

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Spectra Energy Corp

Condensed Consolidating Balance Sheet

December 31, 2011

(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Cash and cash equivalents	$	$ 2	$ 172	$	$ 174
Receivables consolidated subsidiaries			1	(1)	
Receivables other			962		962
Accrued taxes receivables consolidated subsidiaries	46			(46)	
Other current assets	57	5	566		628
Total current assets	103	7	1,701	(47)	1,764
Investments in and loans to unconsolidated affiliates		70	1,994		2,064
Investments in consolidated subsidiaries	11,720	14,884		(26,604)	
Advances receivable consolidated subsidiaries		4,116		(4,116)	
Notes receivable consolidated subsidiaries			592	(592)	
Goodwill			4,420		4,420
Other assets	42	105	383		530
Property, plant and equipment, net			18,258		18,258
Regulatory assets and deferred debits	1	15	1,086		1,102
Total Assets	$ 11,866	$ 19,197	$ 28,434	$ (31,359)	$ 28,138
Accounts payable other	$ 3	$ 62	$ 433	$	$ 498
Accounts payable consolidated subsidiaries		1		(1)	
Commercial paper		751	301		1,052
Short-term borrowings consolidated subsidiaries		592		(592)	
Accrued taxes payable		2	80		82
Accrued taxes payable consolidated subsidiaries			46	(46)	
Current maturities of long-term debt			525		525
Other current liabilities	76	75	793		944
Total current liabilities	79	1,483	2,178	(639)	3,101
Long-term debt		3,311	6,835		10,146
Advances payable consolidated subsidiaries	3,534		582	(4,116)	
Deferred credits and other liabilities	188	2,683	2,866		5,737
Preferred stock of subsidiaries			258		258
Equity					
Controlling interests	8,065	11,720	14,884	(26,604)	8,065
Noncontrolling interests			831		831
Total equity	8,065	11,720	15,715	(26,604)	8,896
Total Liabilities and Equity	$ 11,866	$ 19,197	$ 28,434	$ (31,359)	$ 28,138

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Spectra Energy Corp

Condensed Consolidating Statement of Cash Flows

Year Ended December 31, 2012

(In millions)

	Spectra Energy Corp	Spectra Capital(a)	Non-Guarantor Subsidiaries(a)	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES					
Net income	$ 940	$ 917	$ 1,484	$ (2,294)	$ 1,047
Adjustments to reconcile net income to net cash provided by (used in) operating activities:					
Depreciation and amortization			760		760
Equity in earnings of unconsolidated affiliates			(382)		(382)
Equity in earnings of subsidiaries	(917)	(1,377)		2,294	
Distributions received from unconsolidated affiliates			307		307
Other	(86)	246	46		206
Net cash provided by (used in) operating activities	(63)	(214)	2,215		1,938
CASH FLOWS FROM INVESTING ACTIVITIES					
Capital expenditures			(2,025)		(2,025)
Investments in and loans to unconsolidated affiliates			(520)		(520)
Acquisitions, net of cash acquired			(30)		(30)
Purchases of held-to-maturity securities			(2,671)		(2,671)
Proceeds from sales and maturities of held-to-maturity securities			2,578		2,578
Purchases of available-for-sale securities			(644)		(644)
Proceeds from sales and maturities of available-for-sale securities			514		514
Distributions received from unconsolidated affiliates			17		17
Advances from (to) affiliates	(163)	(335)	888	(390)	
Other changes in restricted funds			93		93
Other			14		14
Net cash used in investing activities	(163)	(335)	(1,786)	(390)	(2,674)
CASH FLOWS FROM FINANCING ACTIVITIES					
Proceeds from the issuance of long-term debt			1,301		1,301
Payments for the redemption of long-term debt			(525)		(525)
Net increase (decrease) in commercial paper		(238)	437		199
Net increase in short-term borrowings consolidated affiliates		322		(322)	
Distributions to noncontrolling interests			(120)		(120)
Proceeds from the issuance of Spectra Energy common stock	382				382
Proceeds from the issuance of Spectra Energy Partners common units			145		145
Dividends paid on common stock	(753)				(753)
Distributions and advances from (to) affiliates	564	466	(1,742)	712	
Other	33		(8)		25

Net cash provided by (used in) financing activities	226	550	(512)	390	654
Effect of exchange rate changes on cash			2		2
Net increase (decrease) in cash and cash equivalents		1	(81)		(80)
Cash and cash equivalents at beginning of period		2	172		174
Cash and cash equivalents at end of period	$	$ 3	$ 91	$	$ 94

(a) Excludes the effects of $1,207 million of non-cash equitizations of advances receivable owed to Spectra Capital.

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Spectra Energy Corp

Condensed Consolidating Statement of Cash Flows

Year Ended December 31, 2011

(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES					
Net income	$ 1,184	$ 1,183	$ 1,764	$ (2,849)	$ 1,282
Adjustments to reconcile net income to net cash provided by (used in) operating activities:					
Depreciation and amortization			725		725
Equity in earnings of unconsolidated affiliates			(549)		(549)
Equity in earnings of subsidiaries	(1,183)	(1,666)		2,849	
Distributions received from unconsolidated affiliates			499		499
Other	(23)	276	(24)		229
Net cash provided by (used in) operating activities	(22)	(207)	2,415		2,186
CASH FLOWS FROM INVESTING ACTIVITIES					
Capital expenditures			(1,915)		(1,915)
Investments in and loans to unconsolidated affiliates			(4)		(4)
Acquisitions, net of cash acquired			(390)		(390)
Purchases of held-to-maturity securities			(1,695)		(1,695)
Proceeds from sales and maturities of held-to-maturity securities			1,709		1,709
Purchases of available-for-sale securities			(953)		(953)
Proceeds from sales and maturities of available-for-sale securities			1,143		1,143
Distributions received from unconsolidated affiliates			17		17
Advances to affiliates		(422)		422	
Other changes in restricted funds			(64)		(64)
Other			54		54
Net cash used in investing activities		(422)	(2,098)	422	(2,098)
CASH FLOWS FROM FINANCING ACTIVITIES					
Proceeds from the issuance of long-term debt			1,118		1,118
Payments for the redemption of long-term debt			(531)		(531)
Net increase in commercial paper		73	167		240
Net decrease in revolving credit facilities borrowings			(299)		(299)
Distributions to noncontrolling interests			(101)		(101)
Proceeds from the issuance of Spectra Energy Partners common units			213		213
Dividends paid on common stock	(694)				(694)
Distributions and advances from (to) affiliates	681	558	(817)	(422)	
Other	35		(16)		19
Net cash provided by (used in) financing activities	22	631	(266)	(422)	(35)

Effect of exchange rate changes on cash			(9)		(9)
Net increase in cash and cash equivalents		2	42		44
Cash and cash equivalents at beginning of period			130		130
Cash and cash equivalents at end of period	$	$ 2	$ 172	$	$ 174

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Spectra Energy Corp

Condensed Consolidating Statement of Cash Flows

Year Ended December 31, 2010

(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES					
Net income	$ 1,049	$ 1,062	$ 1,572	$ (2,554)	$ 1,129
Adjustments to reconcile net income to net cash provided by (used in) operating activities:					
Depreciation and amortization			664		664
Equity in earnings of unconsolidated affiliates			(430)		(430)
Equity in earnings of subsidiaries	(1,062)	(1,492)		2,554	
Distributions received from unconsolidated affiliates			391		391
Other	(239)	122	(229)		(346)
Net cash provided by (used in) operating activities	(252)	(308)	1,968		1,408
CASH FLOWS FROM INVESTING ACTIVITIES					
Capital expenditures			(1,346)		(1,346)
Investments in and loans to unconsolidated affiliates			(10)		(10)
Acquisitions, net of cash acquired			(492)		(492)
Purchases of held-to-maturity securities			(1,117)		(1,117)
Proceeds from sales and maturities of held-to-maturity securities			1,068		1,068
Purchases of available-for-sale securities			(254)		(254)
Proceeds from sales and maturities of available-for-sale securities			38		38
Distributions received from unconsolidated affiliates			17		17
Advances to affiliates		(983)	(224)	1,207	
Other			(5)		(5)
Net cash used in investing activities		(983)	(2,325)	1,207	(2,101)
CASH FLOWS FROM FINANCING ACTIVITIES					
Proceeds from the issuance of long-term debt			1,232		1,232
Payments for the redemption of long-term debt			(807)		(807)
Net increase in commercial paper		637	32		669
Net increase in short-term borrowings from affiliates		225		(225)	
Net increase in revolving credit facilities borrowings			58		58
Distributions to noncontrolling interests			(73)		(73)
Proceeds from the issuance of Spectra Energy Partners common units			216		216
Dividends paid on common stock	(650)	(3)		3	(650)
Distributions and advances from (to) affiliates	887	432	(334)	(985)	
Other	15		(4)		11
Net cash provided by financing activities	252	1,291	320	(1,207)	656

Effect of exchange rate changes on cash			1		1
Net decrease in cash and cash equivalents			(36)		(36)
Cash and cash equivalents at beginning of period			166		166
Cash and cash equivalents at end of period	$	$	$ 130	$	$ 130

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26. Quarterly Financial Data (Unaudited)

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
	(in millions, except per share amounts)				
2012					
Operating revenues	$ 1,544	$ 1,112	$ 1,072	$ 1,347	$ 5,075
Operating income	519	367	328	361	1,575
Net income	361	241	204	241	1,047
Net income controlling interests	333	215	179	213	940
Earnings per share (a)					
Basic	0.51	0.33	0.27	0.32	1.44
Diluted	0.51	0.33	0.27	0.32	1.43
2011					
Operating revenues	1,612	1,188	1,123	1,428	5,351
Operating income	557	402	361	443	1,763
Net income	382	307	281	312	1,282
Net income controlling interests	357	284	254	289	1,184
Earnings per share (a)					
Basic	0.55	0.44	0.39	0.44	1.82
Diluted	0.55	0.44	0.39	0.44	1.81

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

Unusual or Infrequent Items

During the fourth quarter of 2012, we recorded the impacts of an unfavorable regulatory decision at Union Gas. The impacts of this decision reduced operating revenues and operating income by $38 million, and net income and net income controlling interests by $28 million.

27. Subsequent Events

As of February 22, 2013, we had borrowed $250 million under our delayed-draw term loan agreement. Borrowings under the agreement are LIBOR-based and are due in December 2015. See Note 15 for further discussion of the delayed-draw term loan agreement.

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SPECTRA ENERGY CORP

SCHEDULE II VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

	Balance at Beginning of Period	Additions: Charged to Expense	Additions: Charged to Other Accounts	Deductions (a)	Balance at End of Period
			(in millions)		
December 31, 2012					
Allowance for doubtful accounts	$ 14	$ 10	$ 1	$ 12	$ 13
Other (b)	171	64		54	181
	$ 185	$ 74	$ 1	$ 66	$ 194
December 31, 2011					
Allowance for doubtful accounts	$ 9	$ 10	$ 2	$ 7	$ 14
Other (b)	155	48	2	34	171
	$ 164	$ 58	$ 4	$ 41	$ 185
December 31, 2010					
Allowance for doubtful accounts	$ 14	$ 5	$ 1	$ 11	$ 9
Other (b)	139	33	28	45	155
	$ 153	$ 38	$ 29	$ 56	$ 164

(a) Principally cash payments and reserve reversals.

(b) Principally income tax, insurance-related, litigation and other reserves, included primarily in Deferred Credits and Other Liabilities Regulatory and Other on the Consolidated Balance Sheets.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure.

None.

Item 9A. Controls and Procedures.

Evaluation of Disclosure Controls and Procedures

Disclosure controls and procedures are controls and other procedures that are designed to ensure that information required to be disclosed by us in the reports we file or submit under the Securities Exchange Act of 1934 (Exchange Act) is recorded, processed, summarized, and reported within the time periods specified by the SEC s rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to provide reasonable assurance that information required to be disclosed by us in the reports we file or submit under the Exchange Act is accumulated and communicated to management, including the Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Under the supervision and with the participation of management, including the Chief Executive Officer and Chief Financial Officer, we have evaluated the effectiveness of our disclosure controls and procedures (as such term is defined in Rule 13a-15(e) and 15d-15(e) under the Exchange Act) as of December 31, 2012, and, based upon this evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that these controls and procedures are effective at the reasonable assurance level.

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Changes in Internal Control over Financial Reporting

Under the supervision and with the participation of management, including the Chief Executive Officer and Chief Financial Officer, we have evaluated changes in internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) that occurred during the fiscal quarter ended December 31, 2012 and found no change that has materially affected, or is reasonably likely to materially affect, internal control over financial reporting.

Management s Annual Report on Internal Control over Financial Reporting

The report of management required under this Item 9A is contained in Item 8. Financial Statements and Supplementary Data, Management s Annual Report on Internal Control over Financial Reporting.

Attestation Report of Independent Registered Public Accounting Firm

The attestation report required under this Item 9A is contained in Item 8. Financial Statements and Supplementary Data, Report of Independent Registered Public Accounting Firm.

Item 9B. Other Information.

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance.

Reference to Executive Officers is included in Part I. Item 1. Business of this report. Other information in response to this item is incorporated by reference from our Proxy Statement relating to our 2013 annual meeting of shareholders.

Item 11. Executive Compensation.

Information in response to this item is incorporated by reference from our Proxy Statement relating to our 2013 annual meeting of shareholders.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.

Information in response to this item is incorporated by reference from our Proxy Statement relating to our 2013 annual meeting of shareholders.

Item 13. Certain Relationships and Related Transactions, and Director Independence.

Information in response to this item is incorporated by reference from our Proxy Statement relating to our 2013 annual meeting of shareholders.

Item 14. Principal Accounting Fees and Services.

Information in response to this item is incorporated by reference from our Proxy Statement relating to our 2013 annual meeting of shareholders.

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PART IV

Item 15. Exhibits, Financial Statement Schedules.

(a) Consolidated Financial Statements, Supplemental Financial Data and Supplemental Schedules included in Part II of this annual report are as follows:

Spectra Energy Corp:

Report of Independent Registered Accounting Firm

Consolidated Statements of Operations

Consolidated Statements of Comprehensive Income

Consolidated Balance Sheets

Consolidated Statements of Cash Flows

Consolidated Statements of Equity

Notes to Consolidated Financial Statements

Consolidated Financial Statement Schedule II Valuation and Qualifying Accounts and Reserves

Separate Financial Statements of Subsidiaries not Consolidated Pursuant to Rule 3-09 of Regulation S-X:

DCP Midstream, LLC:

Independent Auditors Report

Consolidated Balance Sheets

Consolidated Statements of Operations

Consolidated Statements of Comprehensive Income

Consolidated Statements of Cash Flows

Consolidated Statements of Changes in Equity

Notes to Consolidated Financial Statements

All other schedules are omitted because they are not required or because the required information is included in the Consolidated Financial Statements or Notes.

(c) Exhibits See Exhibit Index immediately following the signature page.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

Date: February 22, 2013

SPECTRA ENERGY CORP

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

President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the date indicated.

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

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

(iii) Allen C. Capps*
Vice President and Controller (Principal Accounting Officer)

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

Austin A. Adams*

Director

Joseph Alvarado*

Director

Pamela L. Carter*

Director

F. Anthony Comper*

Director

Peter B. Hamilton*

Director

Dennis R. Hendrix*

Director

Michael McShane*

Director

Joseph H. Netherland*

Director

Michael E.J. Phelps *

Director

Date: February 22, 2013

J. Patrick Reddy, by signing his name hereto, does hereby sign this document on behalf of the registrant and on behalf of each of the above-named persons previously indicated by asterisk pursuant to a power of attorney duly executed by the registrant and such persons, filed with the Securities and Exchange Commission as an exhibit hereto.

By:	/s/	J. Patrick Reddy J. Patrick Reddy Attorney-In-Fact

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DCP MIDSTREAM, LLC

CONSOLIDATED FINANCIAL STATEMENTS

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INDEPENDENT AUDITORS REPORT

To the Board of Directors and Members of

DCP Midstream, LLC

Denver, Colorado

We have audited the accompanying consolidated financial statements of DCP Midstream, LLC and its subsidiaries (the Company), which comprise the consolidated balance sheets as of December 31, 2012 and 2011, and the related consolidated statements of operations, comprehensive income, changes in equity, and cash flows for each of the three years in the period ended December 31, 2012, and the related notes to the consolidated financial statements.

Management s Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with accounting principles generally accepted in the United States of America; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor s judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the Company s preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company s internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of DCP Midstream, LLC and its subsidiaries as of December 31, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012, in accordance with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP

February 22, 2013

Member of

Deloitte Touche Tohmatsu

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DCP MIDSTREAM, LLC

CONSOLIDATED BALANCE SHEETS

(millions)

	December 31, 2012	December 31, 2011
ASSETS		
Current assets:		
Cash and cash equivalents	$ 4	$ 9
Accounts receivable:		
Customers, net of allowance for doubtful accounts of $2 million each period	886	981
Affiliates	172	307
Other	35	44
Inventories	105	105
Unrealized gains on derivative instruments	57	107
Other	30	24
Total current assets	1,289	1,577
Property, plant and equipment, net	7,331	6,448
Investments in unconsolidated affiliates	872	154
Intangible assets, net	336	362
Goodwill	723	723
Unrealized gains on derivative instruments	10	23
Other long-term assets	223	125
Total assets	$ 10,784	$ 9,412
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable:		
Trade	$ 1,065	$ 1,547
Affiliates	37	127
Other	51	49
Short-term borrowings	958	370
Distributions payable to members		95
Current maturities of long-term debt	250	
Unrealized losses on derivative instruments	65	113
Accrued taxes	32	36
Capital spending accrual	99	84
Other	218	226
Total current liabilities	2,775	2,647
Deferred income taxes	92	93
Long-term debt	4,443	3,820
Unrealized losses on derivative instruments	11	40
Other long-term liabilities	146	123
Total liabilities	7,467	6,723
Commitments and contingent liabilities		
Equity:		
Members interest	2,413	2,164
Accumulated other comprehensive loss	(9)	(12)

Total members equity		2,404		2,152
Noncontrolling interest		913		537
Total equity		3,317		2,689
Total liabilities and equity	$	10,784	$	9,412

See Notes to Consolidated Financial Statements.

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DCP MIDSTREAM, LLC

CONSOLIDATED STATEMENTS OF OPERATIONS

(millions)

	Year Ended December 31, 2012	2011	2010
Operating revenues:			
Sales of natural gas and petroleum products	$ 7,826	$ 9,638	$ 8,163
Sales of natural gas and petroleum products to affiliates	1,886	2,874	2,414
Transportation, storage and processing	373	392	360
Trading and marketing gains, net	86	78	44
Total operating revenues	10,171	12,982	10,981
Operating costs and expenses:			
Purchases of natural gas and petroleum products	7,662	9,400	8,208
Purchases of natural gas and petroleum products from affiliates	510	1,098	736
Operating and maintenance	667	626	551
Depreciation and amortization	291	449	413
General and administrative	297	295	239
Step acquisition equity interest re-measurement gain			(9)
Total operating costs and expenses	9,427	11,868	10,138
Operating income	744	1,114	843
Earnings from unconsolidated affiliates	34	26	34
Interest expense, net	(193)	(213)	(253)
Income before income taxes	585	927	624
Income tax expense	(2)	(3)	(5)
Net income	583	924	619
Net income attributable to noncontrolling interests	(97)	(61)	(27)
Net income attributable to members interests	$ 486	$ 863	$ 592

See Notes to Consolidated Financial Statements.

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DCP MIDSTREAM, LLC

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(millions)

	Year Ended December 31, 2012	2011	2010
Net income	$ 583	$ 924	$ 619
Other comprehensive income:			
Net unrealized gains (losses) on cash flow hedges	1	(16)	(19)
Reclassification of cash flow hedges into earnings	11	20	24
Total other comprehensive income	12	4	5
Total comprehensive income	595	928	624
Total comprehensive income attributable to noncontrolling interests	(106)	(64)	(28)
Total comprehensive income attributable to members interests	$ 489	$ 864	$ 596

See Notes to Consolidated Financial Statements.

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DCP MIDSTREAM, LLC

CONSOLIDATED STATEMENTS OF CASH FLOWS

(millions)

	Year Ended December 31, 2012	2011	2010
Cash flows from operating activities:			
Net income	$ 583	$ 924	$ 619
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	291	449	413
Earnings from unconsolidated affiliates	(34)	(26)	(34)
Distributions from unconsolidated affiliates	36	38	47
Step acquisition equity interest re-measurement gain			(9)
Net unrealized (gains) losses on derivative instruments		(47)	74
Deferred income tax benefit	(1)	(36)	(4)
Other, net	6		(4)
Changes in operating assets and liabilities which provided (used) cash:			
Accounts receivable	241	(63)	(74)
Inventories	(9)	(1)	(5)
Accounts payable	(630)	474	69
Other	(139)	14	(97)
Net cash provided by operating activities	344	1,726	995
Cash flows from investing activities:			
Capital expenditures	(2,285)	(1,113)	(538)
Acquisitions, net of cash acquired	(123)	(439)	(281)
Proceeds from sale of two-thirds interest in Sand Hills and Southern Hills	919		
Investments in unconsolidated affiliates	(240)	(6)	(2)
Proceeds from sale of assets	1	18	2
Purchases of available-for-sale securities			(623)
Proceeds from sales of available-for-sale securities			633
Net cash used in investing activities	(1,728)	(1,540)	(809)
Cash flows from financing activities:			
Payment of dividends and distributions to members	(405)	(789)	(575)
Proceeds from debt	2,915	2,024	1,468
Payment of debt	(2,042)	(1,675)	(1,636)
Proceeds from issuance of common units by a subsidiary, net of offering costs	455	170	189
Proceeds from commercial paper, net	588	183	187
Distributions paid to noncontrolling interests	(112)	(86)	(64)
Purchase of additional interest in a subsidiary			(4)
Deferred financing costs	(20)	(12)	(7)
Net cash provided by (used in) financing activities	1,379	(185)	(442)
Net change in cash and cash equivalents	(5)	1	(256)
Cash and cash equivalents, beginning of period	9	8	264
Cash and cash equivalents, end of period	$ 4	$ 9	$ 8

See Notes to Consolidated Financial Statements.

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DCP MIDSTREAM, LLC

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(millions)

	Members Equity			
	Members Interest	Accumulated Other Comprehensive (Loss) Income	Noncontrolling Interest	Total Equity
Balance, January 1, 2010	$ 2,020	$ (17)	$ 315	$ 2,318
Net income	592		27	619
Other comprehensive income		4	1	5
Dividends and distributions	(581)		(64)	(645)
Purchase of additional interest in a subsidiary			(5)	(5)
Issuance of common units by a subsidiary	42		147	189
Balance, December 31, 2010	2,073	(13)	421	2,481
Net income	863		61	924
Other comprehensive income		1	3	4
Dividends and distributions	(807)		(86)	(893)
Equity-based compensation			3	3
Issuance of common units by a subsidiary, net of offering costs	35		135	170
Balance, December 31, 2011	$ 2,164	$ (12)	$ 537	$ 2,689
Net income	486		97	583
Other comprehensive income		3	9	12
Dividends and distributions	(310)		(112)	(422)
Issuance of common units by a subsidiary, net of offering costs	73		382	455
Balance, December 31, 2012	$ 2,413	$ (9)	$ 913	$ 3,317

See Notes to Consolidated Financial Statements.

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DCP MIDSTREAM, LLC

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Years Ended December 31, 2012, 2011 and 2010

1. Description of Business and Basis of Presentation

DCP Midstream, LLC, with its consolidated subsidiaries, or us, we, our, or the Company, is a joint venture owned 50% by Spectra Energy Corp and its affiliates, or Spectra Energy, and 50% by Phillips 66 and its affiliates, or Phillips 66. We operate in the midstream natural gas industry. Our primary operations consist of gathering, processing, compressing, treating, transporting and storing natural gas and fractionating, transporting, gathering, processing and storing natural gas liquids, or NGLs, and/or condensate as well as marketing, from which we generate revenues primarily by trading and marketing natural gas and NGLs.

DCP Midstream Partners, LP, or DCP Partners, is a master limited partnership, of which we act as general partner. As of December 31, 2012 and 2011, we owned an approximate 27% and 26% limited partner interest, respectively. Additionally, as of December 31, 2012 and 2011, we owned an approximate 1% general partner interest in DCP Partners, for both periods, as well as incentive distribution rights that entitle us to receive an increasing share of available cash as pre-defined distribution targets are achieved. As the general partner of DCP Partners, we have responsibility for its operations. We exercise control over DCP Partners and we account for it as a consolidated subsidiary. Transactions between us and DCP Partners have been identified in the consolidated financial statements as transactions between affiliates.

Prior to May 1, 2012, we were owned 50% by ConocoPhillips. On May 1, 2012, ConocoPhillips created two independent publicly traded companies by separating its downstream businesses, including its 50% ownership interest in us, to a newly formed company, Phillips 66.

We are governed by a five member board of directors, consisting of two voting members from each of our owners and our Chief Executive Officer, a non-voting member. All decisions requiring the approval of our board of directors are made by simple majority vote of the board, but must include at least one vote from both a Spectra Energy and Phillips 66 (or ConocoPhillips prior to May 1, 2012) board member. In the event the board cannot reach a majority decision, the decision is appealed to the Chief Executive Officers of both Spectra Energy and Phillips 66.

The consolidated financial statements include the accounts of the Company and all majority-owned subsidiaries where we have the ability to exercise control and undivided interests in jointly owned assets. We also consolidate DCP Partners, which we control as the general partner and where the limited partners do not have substantive kick-out or participating rights. Investments in greater than 20% owned affiliates that are not variable interest entities and where we do not have the ability to exercise control, and investments in less than 20% owned affiliates where we have the ability to exercise significant influence, are accounted for using the equity method. Intercompany balances and transactions have been eliminated.

Certain amounts in the prior year s consolidated financial statements have been reclassified to the current year presentation.

2. Summary of Significant Accounting Policies

Use of Estimates Conformity with accounting principles generally accepted in the United States of America, or GAAP, requires management to make estimates and assumptions that affect the amounts reported in the consolidated financial statements and notes. Although these estimates are based on management s best available knowledge of current and expected future events, actual results could differ from those estimates.

Cash and Cash Equivalents Cash and cash equivalents include all cash balances and investments in highly liquid financial instruments purchased with an original stated maturity of 90 days or less.

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DCP MIDSTREAM, LLC

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued

Years Ended December 31, 2012, 2011 and 2010

Allowance for Doubtful Accounts Management estimates the amount of required allowances for the potential non-collectability of accounts receivable generally based upon number of days past due, past collection experience and consideration of other relevant factors. However, past experience may not be indicative of future collections and therefore additional charges could be incurred in the future to reflect differences between estimated and actual collections.

Inventories Inventories, which consist primarily of natural gas and NGLs held in storage for transportation and processing and sales commitments, are recorded at the lower of weighted-average cost or market value. Transportation costs are included in inventory.

Accounting for Risk Management and Derivative Activities and Financial Instruments We designate each energy commodity derivative as either trading or non-trading. Certain non-trading derivatives are further designated as either a hedge of a forecasted transaction or future cash flow (cash flow hedge), a hedge of a recognized asset, liability or firm commitment (fair value hedge), or normal purchases or normal sales contract. The remaining non-trading derivatives, which are related to asset based activities for which the hedge accounting or the normal purchase or normal sale exception is not elected, are recorded at fair value in the consolidated balance sheets as unrealized gains or unrealized losses on derivative instruments, with changes in the fair value recognized in the consolidated statements of operations. For each derivative, the accounting method and presentation of gains and losses or revenue and expense in the consolidated statements of operations are as follows:

Classification of Contract	**Accounting Method**	**Presentation of Gains & Losses or Revenue & Expense**
Trading Derivatives	Mark-to-market method (a)	Net basis in trading and marketing gains and losses
Non-Trading Derivatives:		
Cash Flow Hedge	Hedge method (b)	Gross basis in the same consolidated statements of operations category as the related hedged item
Fair Value Hedge	Hedge method (b)	Gross basis in the same consolidated statements of operations category as the related hedged item
Normal Purchases or Normal Sales	Accrual method (c)	Gross basis upon settlement in the corresponding consolidated statements of operations category based on purchase or sale
Non-Trading Derivatives	Mark-to-market method (a)	Net basis in trading and marketing gains and losses

(a) Mark-to-market method An accounting method whereby the change in the fair value of the asset or liability is recognized in the consolidated statements of operations in trading and marketing gains and losses during the current period.

DCP MIDSTREAM, LLC

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued

Years Ended December 31, 2012, 2011 and 2010

(b) Hedge method An accounting method whereby the change in the fair value of the asset or liability is recorded in the consolidated balance sheets as unrealized gains or unrealized losses on derivative instruments. For cash flow hedges, there is no recognition in the consolidated statements of operations for the effective portion until the service is provided or the associated delivery period impacts earnings. For fair value hedges, the changes in the fair value of the asset or liability, as well as the offsetting changes in value of the hedged item, are recognized in the consolidated statements of operations in the same category as the related hedged item.

(c) Accrual method An accounting method whereby there is no recognition in the consolidated balance sheets or consolidated statements of operations for changes in fair value of a contract until the service is provided or the associated delivery period impacts earnings.

Cash Flow and Fair Value Hedges For derivatives designated as a cash flow hedge or a fair value hedge, we maintain formal documentation of the hedge. In addition, we formally assess both at the inception of the hedging relationship and on an ongoing basis, whether the hedge contract is highly effective in offsetting changes in cash flows or fair values of hedged items. All components of each derivative gain or loss are included in the assessment of hedge effectiveness, unless otherwise noted.

The fair value of a derivative designated as a cash flow hedge is recorded in the consolidated balance sheets as unrealized gains or unrealized losses on derivative instruments. The effective portion of the change in fair value of a derivative designated as a cash flow hedge is recorded in the consolidated balance sheets as AOCI and the ineffective portion is recorded in the consolidated statements of operations. During the period in which the hedged transaction impacts earnings, amounts in AOCI associated with the hedged transaction are reclassified to the consolidated statements of operations in the same accounts as the item being hedged. Hedge accounting is discontinued prospectively when it is determined that the derivative no longer qualifies as an effective hedge, or when it is probable that the hedged transaction will not occur. When hedge accounting is discontinued because the derivative no longer qualifies as an effective hedge, the derivative is subject to the mark-to-market accounting method prospectively. The derivative continues to be carried on the consolidated balance sheets at its fair value; however, subsequent changes in its fair value are recognized in current period earnings. Gains and losses related to discontinued hedges that were previously accumulated in AOCI will remain in AOCI until the hedged transaction impacts earnings, unless it is probable that the hedged transaction will not occur, in which case, the gains and losses that were previously deferred in AOCI will be immediately recognized in current period earnings.

The fair value of a derivative designated as a fair value hedge is recorded for balance sheet purposes as unrealized gains or unrealized losses on derivative instruments. We recognize the gain or loss on the derivative instrument, as well as the offsetting loss or gain on the hedged item in earnings in the current period. All derivatives designated and accounted for as fair value hedges are classified in the same category as the item being hedged in the consolidated results of operations.

Valuation When available, quoted market prices or prices obtained through external sources are used to determine a contract s fair value. For contracts with a delivery location or duration for which quoted market prices are not available, fair value is determined based on internally developed pricing models developed primarily from historical relationships with quoted market prices and the expected relationship with quoted market prices.

Values are adjusted to reflect the credit risk inherent in the transaction as well as the potential impact of liquidating open positions in an orderly manner over a reasonable time period under current conditions. Changes

DCP MIDSTREAM, LLC

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued

Years Ended December 31, 2012, 2011 and 2010

in market prices and management estimates directly affect the estimated fair value of these contracts. Accordingly, it is reasonably possible that such estimates may change in the near term.

Property, Plant and Equipment Property, plant and equipment are recorded at historical cost. The cost of maintenance and repairs, which are not significant improvements, are expensed when incurred. Depreciation is computed using the straight-line method over the estimated useful lives of the assets.

Asset Retirement Obligations Asset retirement obligations associated with tangible long-lived assets are recorded at fair value in the period in which they are incurred, if a reasonable estimate of fair value can be made, and added to the carrying amount of the associated asset. This additional carrying amount is then depreciated over the life of the asset. The liability is determined using a risk free interest rate and increases due to the passage of time based on the time value of money until the obligation is settled.

Our asset retirement obligations relate primarily to the retirement of various gathering pipelines and processing facilities, obligations related to right-of-way easement agreements, and contractual leases for land use. We adjust our asset retirement obligation each quarter for any liabilities incurred or settled during the period, accretion expense and any revisions made to the estimated cash flows.

Investments in Unconsolidated Affiliates We use the equity method to account for investments in greater than 20% owned affiliates that are not variable interest entities and where we do not have the ability to exercise control, and investments in less than 20% owned affiliates where we have the ability to exercise significant influence.

We evaluate our investments in unconsolidated affiliates for impairment whenever events or changes in circumstances indicate that the carrying value of such investments may have experienced an other than temporary decline in value. When there is evidence of loss in value, we compare the estimated fair value of the investment to the carrying value of the investment to determine whether impairment has occurred. We assess the fair value of our investments in unconsolidated affiliates using commonly accepted techniques, and may use more than one method, including, but not limited to, recent third party comparable sales and discounted cash flow models. If the estimated fair value is considered to be permanently less than the carrying value and management considers the decline in value to be other than temporary, the excess of the carrying value over the estimated fair value is recognized as an impairment loss.

Goodwill and Intangible Assets Goodwill is the cost of an acquisition less the fair value of the net assets of the acquired business. We perform an annual impairment test of goodwill in the third quarter, and update the test during interim periods when we believe events or changes in circumstances indicate that we may not be able to recover the carrying value of a reporting unit. We primarily use a discounted cash flow analysis to perform the assessment. Key assumptions in the analysis include the use of an appropriate discount rate, terminal year multiples, and estimated future cash flows including an estimate of operating and general and administrative costs. In estimating cash flows, we incorporate current market information, as well as historical and other factors, into our forecasted commodity prices. For certain reporting units, we may elect to first assess qualitative factors to determine whether it is more likely than not that the fair value of our reporting units is less than the carrying value. If actual results are not consistent with our assumptions and estimates, or our assumptions and estimates change due to new information, we may be exposed to goodwill impairment charges, which would be recognized in the period in which the carrying value exceeds fair value.

Intangible assets consist primarily of customer contracts, including commodity purchase, transportation and processing contracts and related relationships. These intangible assets are amortized on a straight-line basis over

DCP MIDSTREAM, LLC

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued

Years Ended December 31, 2012, 2011 and 2010

the period of expected future benefit. Intangible assets are removed from the gross carrying amount and the total of accumulated amortization in the period in which they become fully amortized.

Long-Lived Assets We evaluate whether the carrying value of long-lived assets has been impaired when circumstances indicate the carrying value of those assets may not be recoverable. This evaluation is based on undiscounted cash flow projections. The carrying amount is not recoverable if it exceeds the sum of the undiscounted cash flows expected to result from the use and eventual disposition of the asset. We consider various factors when determining if these assets should be evaluated for impairment, including but not limited to:

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

If the carrying value is not recoverable, the impairment loss is measured as the excess of the asset s carrying value over its fair value. We assess the fair value of long-lived assets using commonly accepted techniques, and may use more than one method, including, but not limited to, recent third party comparable sales and discounted cash flow models. Significant changes in market conditions resulting from events such as the condition of an asset or a change in management s intent to utilize the asset would generally require management to reassess the cash flows related to the long-lived assets.

Unamortized Debt Premium, Discount and Expense Premiums, discounts and expenses incurred with the issuance of long-term debt are amortized over the term of the debt using the effective interest method. These premiums and discounts are recorded on the consolidated balance sheets within long-term debt. These unamortized expenses are recorded on the consolidated balance sheets as other long-term assets.

Noncontrolling Interest Noncontrolling interest represents the ownership interests of third-party entities in the net assets of consolidated affiliates, including ownership interest of DCP Partners public unitholders, through DCP Partners publicly traded common units, in net assets of DCP Partners and the noncontrolling interest which is recorded in DCP Partners consolidated balance sheets. For financial reporting purposes, the assets and liabilities of these entities are consolidated with those of our own, with any third party interest in our consolidated balance sheet amounts shown as noncontrolling interest in equity. Distributions to and contributions from noncontrolling interests represent cash payments to and cash contributions from, respectively, such third-party investors.

Dividends and Distributions Under the terms of the Second Amended and Restated LLC Agreement dated July 5, 2005, as amended, or the LLC Agreement, we are required to make quarterly distributions to Spectra Energy and Phillips 66 (or ConocoPhillips prior to May 1, 2012) based on allocated taxable income. The LLC Agreement provides for taxable income to be allocated in accordance with Internal Revenue Code

DCP MIDSTREAM, LLC

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued

Years Ended December 31, 2012, 2011 and 2010

Section 704(c). This Code Section accounts for the variation between the adjusted tax basis and the fair market value of assets contributed to the joint venture. The distribution is based on the highest taxable income allocated to either member, with the other member receiving a proportionate amount to maintain the ownership capital accounts at 50% for both Spectra Energy and Phillips 66. Tax distributions to the members are calculated based on estimated annual taxable income allocated to the members according to their respective ownership percentages at the date the distributions became due. Our board of directors determines the amount of the periodic dividends to be paid by considering net income attributable to members interests, cash flow or any other criteria deemed appropriate. The LLC Agreement restricts payment of dividends except with the approval of both members. Dividends are allocated to the members in accordance with their respective ownership percentages.

DCP Partners considers the payment of a quarterly distribution to the holders of its common units, to the extent DCP Partners has sufficient cash from its operations after establishment of cash reserves and payment of fees and expenses, including payments to its general partner, a wholly-owned subsidiary of ours. There is no guarantee, however, that DCP Partners will pay the minimum quarterly distribution on the units in any quarter. DCP Partners will be prohibited from making any distributions to unitholders if it would cause an event of default, or an event of default exists, under its credit agreement.

Revenue Recognition We generate the majority of our revenues from natural gas gathering, processing, compressing, treating, transporting and storing and NGL fractionating, transporting, gathering, processing and storing, as well as trading and marketing of natural gas and NGLs. We realize revenues either by selling the residue natural gas and NGLs, or by receiving fees.

We obtain access to commodities and provide our midstream services principally under contracts that contain a combination of one or more of the following arrangements:

Fee-based arrangements Under fee-based arrangements, we receive a fee or fees for one or more of the following services: gathering, compressing, treating, processing, storing, or transporting of natural gas, and fractionating, storing and transporting NGLs. Our fee-based arrangements include natural gas purchase arrangements pursuant to which we purchase 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 we would otherwise charge for gathering of natural gas from the wellhead location to the delivery point. The revenues we earn are directly related to the volume of natural gas or NGLs that flows through our systems and are not directly dependent on commodity prices. However, to the extent a sustained decline in commodity prices results in a decline in volumes our revenues from these arrangements would be reduced.

Percent-of-proceeds/index arrangements Under percent-of-proceeds/index arrangements, we generally purchase natural gas from producers at the wellhead or other receipt points, gather the wellhead natural gas through our gathering system, treat and process the natural gas, and then sell the resulting residue natural gas and NGLs based on index prices from published index market prices. We remit to the producers either an agreed-upon percentage of the actual proceeds that we receive from our sales of the residue natural gas and NGLs, or an agreed-upon percentage of the proceeds based on index related prices for the natural gas and the NGLs, regardless of the actual amount of the sales proceeds we receive. Certain of these arrangements may also result in our returning all or a portion of the residue natural gas and/or the NGLs to the producer, in lieu of returning sales proceeds. Our revenues under percent-of-proceeds/index arrangements relate directly with the price of natural gas and/or NGLs.

DCP MIDSTREAM, LLC

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued

Years Ended December 31, 2012, 2011 and 2010

Keep-whole and wellhead purchase arrangements Under the terms of a keep-whole processing contract, we gather natural gas from the producer for processing, market the NGLs and return to the producer residue natural gas with a British thermal unit, or 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, we purchase natural gas from the producer at the wellhead or defined receipt point for processing and then market the resulting NGLs and residue gas at market prices. Under these types of contracts, we are 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. We benefit in periods when NGL prices are higher relative to natural gas prices.

Our trading and marketing of natural gas and petroleum products consists of physical purchases and sales, as well as derivative instruments.

We recognize revenues for sales and services under the four revenue recognition criteria, as follows:

Persuasive evidence of an arrangement exists Our customary practice is to enter into a written contract.

Delivery Delivery is deemed to have occurred at the time custody is transferred, or in the case of fee-based arrangements, when the services are rendered. To the extent we retain product as inventory, delivery occurs when the inventory is subsequently sold and custody is transferred to the third party purchaser.

The fee is fixed or determinable We negotiate the fee for our services at the outset of our fee-based arrangements. In these arrangements, the fees are nonrefundable. For other arrangements, the amount of revenue, based on contractual terms, is determinable when the sale of the applicable product has been completed upon delivery and transfer of custody.

Collectability is reasonably assured Collectability is evaluated on a customer-by-customer basis. New and existing customers are subject to a credit review process, which evaluates the customers financial position (for example, credit metrics, liquidity and credit rating) and their ability to pay. If collectability is not considered probable at the outset of an arrangement in accordance with our credit review process, revenue is not recognized until the cash is collected.

We generally report revenues gross in the consolidated statements of operations, as we typically act as the principal in these transactions, take custody of the product, and incur the risks and rewards of ownership. New or amended contracts for certain sales and purchases of inventory with the same counterparty, when entered into in contemplation of one another, are reported net as one transaction. We recognize revenues for our NGL and residue gas derivative trading activities net in the consolidated statements of operations as trading and marketing gains and losses. These activities include mark-to-market gains and losses on energy trading contracts, and the settlement of financial or physical energy trading contracts.

Revenue for goods and services provided but not invoiced is estimated each month and recorded along with related purchases of goods and services used but not invoiced. These estimates are generally based on estimated commodity prices, preliminary throughput measurements and allocations and contract data. There are no material differences between the actual amounts and the estimated amounts of revenues and purchases recorded at December 31, 2012, 2011 and 2010.

DCP MIDSTREAM, LLC

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued

Years Ended December 31, 2012, 2011 and 2010

Quantities of natural gas or NGLs over-delivered or under-delivered related to imbalance agreements with customers, producers or pipelines are recorded monthly as accounts receivable or accounts payable using current market prices or the weighted-average prices of natural gas or NGLs at the plant or system. These balances are settled with deliveries of natural gas or NGLs, or with cash. Included in the consolidated balance sheets as accounts receivable other as of December 31, 2012 and 2011 were imbalances totaling $35 million and $44 million, respectively. Included in the consolidated balance sheets as accounts payable other, as of December 31, 2012 and 2011 were imbalances totaling $51 million and $49 million, respectively.

Significant Customers Phillips 66 (or ConocoPhillips prior to May 1, 2012), a related party, was a significant customer in each of the past three years. See Note 4 Agreements and Transactions with Related Parties and Affiliates.

Environmental Expenditures Environmental expenditures are expensed or capitalized as appropriate, depending upon the future economic benefit. Expenditures that relate to an existing condition caused by past operations, and that do not generate current or future revenue, are expensed. Liabilities for these expenditures are recorded on an undiscounted basis when environmental assessments and/or clean-ups are probable and the costs can be reasonably estimated.

Equity-Based Compensation Liability classified equity-based compensation cost is remeasured at each reporting date at fair value, based on the closing security price, and is recognized as expense over the requisite service period. Compensation expense for awards with graded vesting provisions is recognized on a straight-line basis over the requisite service period of each separately vesting portion of the award. Awards granted to non-employees for acquiring, or in conjunction with selling, goods and services are measured at the estimated fair value of the goods or services, or the fair value of the award, whichever is more reliably measured.

Accounting for Sales of Units by a Subsidiary We account for sales of units by a subsidiary by recording an increase in members interest equal to the amount of net proceeds received in excess of the carrying value of the units sold. The remaining net proceeds are recorded as an increase to noncontrolling interest.

Capitalized Interest We capitalize interest during construction on major projects. Interest is calculated on the monthly outstanding capital balance and ceases in the month that the asset is placed into service. We also capitalize interest on our equity method investments which are devoting substantially all efforts to establishing a new business and have not yet begun planned principal operations. Capitalization ceases when the investee commences planned principal operations. The rates used to calculate capitalized interest are the weighted-average cost of debt, including the impact of interest rate swaps.

Income Taxes We are structured as a limited liability company, which is a pass-through entity for federal income tax purposes. We own a corporation that files its own federal, foreign and state corporate income tax returns. The income tax expense related to this corporation is included in our income tax expense, along with state, local, franchise and margin taxes of the limited liability company and other subsidiaries.

We follow the asset and liability method of accounting for income taxes. Under this method, deferred income taxes are recognized for the tax consequences of temporary differences between the financial statement carrying amounts and the tax basis of the assets and liabilities. Our taxable income or loss, which may vary substantially from the net income or loss reported in the consolidated statements of operations, is included in the federal returns of each partner.

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3. Acquisitions

On July 3, 2012, DCP Partners acquired the Crossroads processing plant and associated gathering system, or the Crossroads System, from Penn Virginia Resource Partners, L.P. for $63 million. DCP Partners financed the acquisition with borrowings under its revolving credit facility. The Crossroads System, located in the southeastern portion of Harrison County in East Texas, includes approximately 8 miles of gas gathering pipeline, an 80 million cubic feet per day, or MMcf/d, cryogenic processing plant, approximately 20 miles of NGL pipeline and a 50% ownership interest in an approximately 11-mile residue gas pipeline, or CrossPoint Pipeline, LLC, which is accounted for as an unconsolidated affiliate using the equity method.

DCP Partners has accounted for the Crossroads System business combination using estimates of the fair value of assets acquired and liabilities assumed. The preliminary estimates of the fair value of identifiable assets acquired and liabilities assumed are subject to revisions, which may result in adjustments in the preliminary values as additional information relative to the fair value of assets and liabilities becomes available. The values assigned to the assets acquired and liabilities assumed may change in subsequent financial statements pending the final estimates of fair value. The following table summarizes the aggregate consideration and fair value of the identifiable assets acquired and liabilities assumed in the acquisition of Crossroads as of the acquisition date:

	July 3, 2012 (millions)
Aggregate consideration	$ 63
Accounts receivable	$ 4
Property, plant and equipment	63
Investments in unconsolidated affiliates	6
Other current liabilities	(4)
Other long-term liabilities	(6)
Total	$ 63

On April 12, 2012, DCP Partners announced that it has acquired a 10% ownership interest in the Texas Express Pipeline joint venture, from the operator, Enterprise Products Partners L.P., or Enterprise, representing an approximate investment of $85 million in the joint venture. In conjunction with the agreement, DCP Partners paid $11 million for its 10% ownership interest in the Texas Express Pipeline joint venture, representing DCP Partners share of the investment through the closing date. DCP Partners will be responsible for spending approximately $75 million for its share of the remaining construction costs of the pipeline. Originating near Skellytown in Carson County, Texas, the 20-inch diameter Texas Express Pipeline will extend approximately 580 miles to Enterprise s NGL fractionation and storage complex in Mont Belvieu, Texas, and will provide access to other third-party facilities in the area. The Texas Express Pipeline will have an initial capacity of approximately 280,000 barrels per day, or Bbls/d. The Texas Express Pipeline has long-term, fee-based, ship-or-pay transportation commitments, including a commitment from us of 20,000 Bbls/d. Enterprise will construct and operate the pipeline, which is expected to be completed by the second quarter of 2013.

On April 12, 2012, we announced we have entered into an agreement with Enterprise and Anadarko Petroleum Corporation, or Anadarko, to design and construct a new NGL pipeline, or the Front Range Pipeline, that will originate in the Denver-Julesburg Basin, or the DJ Basin, in Colorado and extend approximately 435 miles to Skellytown, Texas. We, Enterprise and Anadarko each hold a 33.33% interest in the Front Range Pipeline. The Front Range Pipeline will connect to third-party systems and the Texas Express Pipeline, and will

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provide takeaway capacity and market access to the Gulf Coast markets. The Front Range Pipeline will have an initial capacity of approximately 150,000 Bbls/d. The Front Range Pipeline has long-term, fee-based, ship-or-pay transportation commitments, including a commitment from us of 40,000 Bbls/d, which will increase to 48,000 Bbls/d in 2019. Enterprise will construct and operate the pipeline, which is expected to be in service in the fourth quarter of 2013.

4. Agreements and Transactions with Related Parties and Affiliates

Dividends and Distributions

During the years ended December 31, 2012, 2011 and 2010, we paid tax distributions of $244 million, $281 million and $275 million, respectively, based on estimated annual taxable income allocated to Spectra Energy and Phillips 66 (or ConocoPhillips prior to May 1, 2012) according to their respective ownership percentages at the date the distributions became due. During the years ended December 31, 2012, 2011 and 2010, we declared and paid dividends of $161 million, $508 million and $300 million, respectively, to Spectra Energy and Phillips 66 (or ConocoPhillips prior to May 1, 2012), allocated in accordance with their respective ownership percentages.

During the years ended December 31, 2012, 2011 and 2010, DCP Partners paid distributions of $106 million, $79 million and $57 million, respectively, to its public unitholders.

DCP Sand Hills Pipeline, LLC and DCP Southern Hills Pipeline, LLC

During the fourth quarter of 2012, we completed the sale of a one-third interest in Sand Hills Pipeline, LLC, or Sand Hills, and Southern Hills Pipeline, LLC, or Southern Hills, to both Spectra Energy and Phillips 66, for aggregate consideration of approximately $919 million. The proceeds from this transaction were used to repay borrowings under our term loan and for general corporate purposes. As a result of this transaction, we, Spectra Energy and Phillips 66 each own a one-third interest in the two pipeline projects.

Phillips 66 and ConocoPhillips

Prior to May 1, 2012, we were owned 50% by ConocoPhillips. On May 1, 2012, ConocoPhillips created two independent publicly traded companies by separating its downstream businesses, including its 50% ownership interest in us, to a newly formed company, Phillips 66. In connection with this transaction, or the Phillips 66 separation, ConocoPhillips is not considered a related party for periods after May 1, 2012. In connection with the Phillips 66 separation, as of May 1, 2012, Chevron Phillips Chemical, or CP Chem, is owned 50 percent by Phillips 66 and will continue to be considered a related party for periods after May 1, 2012.

Long-Term NGL Purchases Contract and Transactions We sell a portion of our residue gas to ConocoPhillips and sell a portion of our NGLs to Phillips 66 and CP Chem. In addition, we purchase natural gas from and provide gathering, transportation and other services to ConocoPhillips. Approximately 40% of our NGL production is committed to Phillips 66 (or ConocoPhillips prior to May 1, 2012) and CP Chem under an existing 15-year contract, which expires in 2015. Should the contract not be renegotiated or renewed, it provides for a five year ratable wind-down period through 2020. The NGL contract also grants Phillips 66 (or ConocoPhillips prior to May 1, 2012) the right to purchase at index-based prices certain quantities of NGLs produced at processing plants that are acquired and/or constructed by us in the future in various counties in the Mid-Continent and Permian Basin regions, and the Austin Chalk area. We anticipate continuing to purchase and sell commodities with ConocoPhillips as a third-party and with Phillips 66 and CP Chem as related parties, in the ordinary course of business.

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We are party to a 15-year gathering and processing agreement with ConocoPhillips, which expires in January 2026, whereby ConocoPhillips has dedicated all of its natural gas production within an area of mutual interest in Oklahoma and Texas. This contract replaces and extends certain contracts that we previously had with ConocoPhillips, and is considered a third-party contract for periods after May 1, 2012.

Spectra Energy

Commodity Transactions We sell a portion of our residue gas and NGLs to, purchase natural gas and other petroleum products from, and provide gathering, transportation and other services to Spectra Energy. Management anticipates continuing to purchase and sell commodities and provide services to Spectra Energy in the ordinary course of business.

DCP Partners had propane supply agreements with Spectra Energy that expired in April 2012, which provided DCP Partners propane supply at its marine terminals for up to approximately 185 million gallons of propane annually.

DCP Partners

On November 2, 2012, we contributed a 33.33% interest in DCP SC Texas GP, or the Eagle Ford System, and a $43 million fixed price commodity derivative for a three-year period to DCP Partners, for aggregate consideration of $438 million, less customary working capital and other purchase price adjustments of $7 million. DCP Partners financed $344 million of the consideration with a two-year term loan agreement and $87 million was financed by the issuance at closing of an aggregate 1,912,663 of DCP Partners common units to us. These transactions represent transactions between entities under common control. DCP Partners contributed an additional $17 million plus 33.33% of the working capital and construction work in progress for the Goliad Plant to the Eagle Ford System. The Goliad Plant will have gas processing capacity of 200 MMcf/d and it will become part of the existing Eagle Ford system. The Goliad Plant will be constructed and funded by DCP SC Texas GP, and will include the new Goliad Plant, a gathering system feeding the plant and ancillary support facilities including compression, liquids handling and residue pipeline interconnect facilities. In connection with this agreement, we also provided DCP Partners with a $7 million two-year direct commodity price hedge for its 33.33% interest in the Goliad Plant project. The Goliad Plant is expected to be completed in the first quarter of 2014.

On July 2, 2012, we contributed our minority ownership interests in two non-operated Mont Belvieu fractionators, or the Mont Belvieu Fractionators, to DCP Partners for aggregate consideration of $200 million, plus $5 million in working capital and other customary purchase price adjustments. DCP Partners entered into a two-year term loan agreement to finance $140 million of the aggregate purchase price. The remaining $60 million consideration was financed with the issuance by DCP Partners of 1,536,098 common units to us. The $140 million cash proceeds we received were used to pay down our short-term borrowings. The Mont Belvieu Fractionators consist of a 12.5 percent interest in the Enterprise Fractionator, which is operated by Enterprise, and a 20 percent interest in the Mont Belvieu I Fractionation Facility, which is operated by ONEOK Partners. We will continue to account for the Mont Belvieu Fractionators through our ownership interest in DCP Partners.

On March 30, 2012, we contributed our remaining 66.67% interest in Southeast Texas Holdings, GP, or Southeast Texas, and derivative instruments related to the Southeast Texas storage business, together the Southeast Texas Midstream Business, to DCP Partners, for consideration of $240 million, plus working capital and other customary purchase price adjustments of $21 million. $192 million of the consideration was financed with a portion of the proceeds from DCP Partners 4.95% 10-year Senior Notes offering. The remaining $48 million consideration was financed with the issuance by DCP Partners of 1,000,417 common units to us. We also

DCP MIDSTREAM, LLC

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provided fixed NGL commodity derivatives for the three year period subsequent to closing valued at $40 million. Certain of the NGL commodity derivatives were valued at $25 million and represent consideration for the termination of a fee-based storage arrangement that we had with DCP Partners in conjunction with its initial 33.33% interest in Southeast Texas; the remaining portion of the commodity derivatives, valued at $15 million, mitigate a portion of DCP Partners currently anticipated commodity price risk associated with the gathering and processing portion of the 66.67% interest in Southeast Texas acquired on March 30, 2012. The contribution of our remaining 66.67% interest in Southeast Texas represents a transaction between entities under common control. As a result of this transaction, DCP Partners owns 100% of the Southeast Texas Midstream Business, and we will continue to consolidate the Southeast Texas Midstream Business through our ownership interest in DCP Partners.

On January 3, 2012, we completed the previously announced contribution of our remaining 49.9% interest in DCP East Texas Holdings, LLC, or East Texas, to DCP Partners, for aggregate consideration of $165 million, less working capital and other purchase price adjustments of approximately $2 million, for a net purchase price of $163 million. DCP Partners financed approximately $130 million of the aggregate purchase price with borrowings under its term loan. The remaining $33 million consideration was financed with the issuance of 727,520 common units to us. As a result of this transaction, DCP Partners owns 100% of East Texas, and we will continue to consolidate East Texas through our ownership interest in DCP Partners.

Transactions with other unconsolidated affiliates

We sell a portion of our residue gas and NGLs to, purchase natural gas and other petroleum products from, and provide gathering and transportation services to, unconsolidated affiliates. We anticipate continuing to purchase and sell commodities and provide services to unconsolidated affiliates in the ordinary course of business.

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The following table summarizes our transactions with related parties and affiliates:

	Year Ended December 31, 2012	2011 (millions)	2010
Phillips 66 (a):			
Sales of natural gas and petroleum products to affiliates	$ 1,028	$	$
Purchases of natural gas and petroleum products from affiliates	$ 21	$	$
Operating and general and administrative expenses	$ 3	$	$
ConocoPhillips (a):			
Sales of natural gas and petroleum products to affiliates	$ 800	$ 2,806	$ 2,365
Transportation, storage and processing	$ 5	$ 15	$ 18
Purchases of natural gas and petroleum products from affiliates	$ 192	$ 616	$ 435
Operating and general and administrative expenses (b)	$ (1)	$ 4	$ 4
Spectra Energy:			
Sales of natural gas and petroleum products to affiliates	$	$ 1	$ 1
Purchases of natural gas and petroleum products from affiliates (c)	$ 181	$ 343	$ 173
Operating and general and administrative expenses	$ 12	$ 15	$ 6
Unconsolidated affiliates:			
Sales of natural gas and petroleum products to affiliates	$ 58	$ 67	$ 48
Transportation, storage and processing	$ 16	$ 17	$ 19
Purchases of natural gas and petroleum products from affiliates	$ 116	$ 139	$ 128

(a) In connection with the Phillips 66 separation, ConocoPhillips is not considered a related party for periods after April 30, 2012 and Phillips 66 is considered a related party for periods starting May 1, 2012.

(b) The year ended December 31, 2012 includes hurricane insurance recovery receivables, which were treated as a reduction to operating expense in the consolidated statements of operations.

(c) Includes a $17 million payment received in December 2010, for reimbursement of damages we incurred when an international propane supplier breached its contract with Spectra Energy.

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We had balances with related parties and affiliates as follows:

	December 31, 2012	December 31, 2011
	(millions)	
Phillips 66 (a):		
Accounts receivable	$ 152	$
Accounts payable	$ (14)	$
Other assets	$ 2	$
ConocoPhillips (a):		
Accounts receivable	$	$ 283
Accounts payable	$	$ (73)
Other assets	$	$ 2
Spectra Energy:		
Accounts payable	$ (6)	$ (30)
Other assets	$ 1	$ 1
Unconsolidated affiliates:		
Accounts receivable	$ 20	$ 24
Accounts payable	$ (17)	$ (24)

(a) In connection with the Phillips 66 separation, ConocoPhillips is not considered a related party for periods after April 30, 2012 and Phillips 66 is considered a related party for periods starting May 1, 2012.

5. Inventories

Inventories were as follows:

	December 31, 2012	December 31, 2011
	(millions)	
Natural gas	$ 23	$ 26
NGLs	82	79
Total inventories	$ 105	$ 105

6. Property, Plant and Equipment

Property, plant and equipment by classification were as follows:

	Depreciable Life	December 31, 2012	December 31, 2011

		(millions)	
Gathering and transmission systems	20 - 50 years	$ 6,919	$ 6,069
Processing, storage and terminal facilities	35 - 60 years	3,035	2,900
Other	3 - 30 years	310	287
Construction work in progress		1,494	1,366
Property, plant and equipment		11,758	10,622
Accumulated depreciation		(4,427)	(4,174)
Property, plant and equipment, net		$ 7,331	$ 6,448

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DCP MIDSTREAM, LLC

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Interest capitalized on construction projects during the years ended December 31, 2012, 2011 and 2010 was $84 million, $22 million and $13 million, respectively. As of December 31, 2012, we had $441 million of non-cancelable purchase obligations for capital projects.

We revised the depreciable lives for our gathering and transmission systems, processing, storage and terminal facilities, and other assets, effective April 1, 2012. The key contributing factors to the change in depreciable lives is an increase in the estimated remaining economically recoverable reserves, resulting from the development of techniques that improve commodity production in the regions our assets serve. Advances in extraction processes, along with improved technology used to locate commodity reserves, is giving producers greater access to unconventional commodities. The new remaining depreciable lives resulted in an approximate $180 million reduction in depreciation expense for the year ended December 31, 2012.

In connection with our evaluation of depreciable lives, we corrected the classification for certain assets within the presentation of our major classes of property, plant and equipment as of December 31, 2011.

Depreciation expense for the years ended December 31, 2012, 2011 and 2010 was $265 million, $423 million and $390 million, respectively.

Asset Retirement Obligations As of December 31, 2012 and 2011, we had $91 million and $73 million, respectively, of asset retirement obligations, or AROs, in other long-term liabilities in the consolidated balance sheets. During the first quarter of 2012, we recorded a change in estimate to increase our AROs by approximately $12 million. The change in estimate was primarily attributable to a reassessment of anticipated timing of settlements and of the original ARO estimated amounts. For the years ended December 31, 2012, 2011 and 2010, accretion expense was $3 million, less than $1 million and $5 million, respectively. Accretion expense is recorded within operating and maintenance expense in our consolidated statements of operations.

The following table summarizes changes in the asset retirement obligations, included in our balance sheets:

	December 31,	
	2012	2011
	(millions)	
Balance, beginning of period	$ 73	$ 79
Accretion expense	3	
Liabilities incurred	15	
Liabilities settled		(6)
Balance, end of period	$ 91	$ 73

We identified various assets as having an indeterminate life, for which there is no requirement to establish a fair value for future retirement obligations associated with such assets. These assets include certain pipelines, gathering systems and processing facilities. A liability for these asset retirement obligations will be recorded only if and when a future retirement obligation with a determinable life is identified. These assets have an indeterminate life because they are owned and will operate for an indeterminate future period when properly maintained. Additionally, if the portion of an owned plant containing asbestos were to be modified or dismantled, we would be legally required to remove the asbestos. We currently have no plans to take actions that would require the removal of the asbestos in these assets. Accordingly, the fair value of the asset retirement obligation related to this asbestos cannot be estimated and no obligation has been recorded.

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7. Goodwill and Intangible Assets

The change in the carrying amount of goodwill is as follows:

	December 31, 2012 (millions)	December 31, 2011 (millions)
Beginning of period	$ 723	$ 721
Acquisitions		2
End of period	$ 723	$ 723

We performed our annual goodwill assessment at the reporting unit level. As a result of our assessment, we concluded that the entire amount of goodwill disclosed on the consolidated balance sheet is recoverable. We used a discounted cash flow analysis to perform the assessment. Key assumptions in the analysis include the use of an appropriate discount rate, terminal year multiples, and estimated future cash flows including an estimate of operating and general and administrative costs. In estimating cash flows, we incorporate current market information, as well as historical and other factors, into our forecasted commodity prices. If actual results are not consistent with our assumptions and estimates, or our assumptions and estimates change due to new information, we may be exposed to goodwill impairment charges, which would be recognized in the period in which the carrying value exceeds fair value.

Intangible assets consist of customer contracts, including commodity purchase, transportation and processing contracts and related relationships. The gross carrying amount and accumulated amortization of these intangible assets are included in the accompanying consolidated balance sheets as intangible assets, net, and are as follows:

	December 31, 2012 (millions)	December 31, 2011 (millions)
Gross carrying amount	$ 524	$ 524
Accumulated amortization	(188)	(162)
Intangible assets, net	$ 336	$ 362

For the years ended December 31, 2012, 2011 and 2010, we recorded amortization expense of $26 million, $26 million and $23 million, respectively. As of December 31, 2012, the remaining amortization periods ranged from less than 1 year to 23 years, with a weighted-average remaining period of approximately 18 years.

Estimated future amortization for these intangible assets is as follows:

	Estimated Future Amortization (millions)
2013	$ 26

2014	20
2015	19
2016	19
2017	19
Thereafter	233
Total	$ 336

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8. Investments in Unconsolidated Affiliates

We had investments in the following unconsolidated affiliates accounted for using the equity method:

	Percentage Ownership	December 31, 2012	2011
		(millions)	
DCP Sand Hills Pipeline, LLC	33.33%	$ 263	$
DCP Southern Hills Pipeline, LLC	33.33%	253	
Discovery Producer Services, LLC	40.00%	222	107
Texas Express Pipeline Joint Venture	10.00%	41	
Main Pass Oil Gathering Company	66.67%	24	27
Front Range Pipeline Joint Venture	33.33%	24	
Mont Belvieu Enterprise Fractionator	12.50%	18	
Mont Belvieu I Fractionation Facility	20.00%	15	12
Other unconsolidated affiliates	Various	12	8
Total investments in unconsolidated affiliates		$ 872	$ 154

During the fourth quarter of 2012, we completed the sale of a one-third interest in Sand Hills Pipeline, LLC, or Sand Hills, and Southern Hills Pipeline, LLC, or Southern Hills, to both Spectra Energy and Phillips 66, for aggregate consideration of approximately $919 million. The proceeds from this transaction were used to repay borrowings under our term loan and for general corporate purposes. As a result of this transaction, we, Spectra Energy and Phillips 66 each own a one-third interest in the two pipeline projects. Prior to this transaction, we accounted for Sand Hills and Southern Hills as consolidated entities. Subsequent to this transaction, we account for Sand Hills and Southern Hills under the equity method of accounting. The Sand Hills and Southern Hills pipeline projects are currently under construction, and we will continue to operate the pipelines. Upon completion of the pipelines, our direct investment is expected to total between $700 million and $800 million.

There was a deficit between the carrying amount of the investment and the underlying equity of Discovery Producer Services, LLC, or Discovery, of $30 million and $33 million at December 31, 2012 and 2011, respectively, which is associated with, and is being amortized over the life of, the underlying long-lived assets of Discovery.

There was an excess of the carrying amount of the investment over the underlying equity of Main Pass Oil Gathering Company, or Main Pass, of $7 million and $8 million at December 31, 2012 and 2011, respectively, which is associated with, and is being amortized over the life of, the underlying long-lived assets of Main Pass.

There was a deficit between the carrying amount of the investment and the underlying equity of Mont Belvieu I Fractionation Facility, or Mont Belvieu I, of $5 million and $6 million at December 31, 2012 and 2011, respectively, which is associated with, and is being amortized over the life of, the underlying long-lived assets of Mont Belvieu I.

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Earnings from unconsolidated affiliates amounted to the following:

	Year Ended December 31, 2012	2011 (in millions)	2010
Discovery Producer Services, LLC	$ 13	$ 22	$ 25
Main Pass Oil Gathering Company			4
Enterprise Fractionator	12		
Mont Belvieu I Fractionation Facility	9	6	5
Other unconsolidated affiliates		(2)	
Total earnings from unconsolidated affiliates	$ 34	$ 26	$ 34

The following tables summarize the combined financial information of unconsolidated affiliates:

	Year Ended December 31, 2012	2011 (millions)	2010
Income statement:			
Operating revenues	$ 431	$ 300	$ 302
Operating expenses	$ 254	$ 219	$ 222
Net income	$ 175	$ 79	$ 78

	December 31, 2012	2011 (millions)
Balance sheet:		
Current assets	$ 165	$ 68
Long-term assets	3,037	499
Current liabilities	(194)	(35)
Long-term liabilities	(67)	(51)
Net assets	$ 2,941	$ 481

9. Fair Value Measurement

Determination of Fair Value

Below is a general description of our valuation methodologies for derivative financial assets and liabilities, which are measured at fair value. Fair values are generally based upon quoted market prices or prices obtained through external sources, where available. If listed market prices or quotes are not available, we determine fair value based upon a market quote, adjusted by other market-based or independently sourced market data such as historical commodity volatilities, crude oil future yield curves, and/or counterparty specific considerations. These adjustments result in a fair value for each asset or liability under an exit price methodology, in line with how we believe a marketplace participant would value that asset or liability. Fair values are adjusted to reflect the credit risk inherent in the transaction as well as the potential impact of liquidating open positions in an orderly manner over a reasonable time period under current conditions. These adjustments may include amounts to reflect counterparty credit quality, the effect of our own creditworthiness, the time value of money and/or the liquidity of the market.

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Counterparty credit valuation adjustments are necessary when the market price of an instrument is not indicative of the fair value as a result of the credit quality of the counterparty. Generally, market quotes assume that all counterparties have near zero, or low, default rates and have equal credit quality. Therefore, an adjustment may be necessary to reflect the credit quality of a specific counterparty to determine the fair value of the instrument. We record counterparty credit valuation adjustments on all derivatives that are in a net asset position as of the measurement date in accordance with our established counterparty credit policy, which takes into account any collateral margin that a counterparty may have posted with us as well as any letters of credit that they have provided.

Entity valuation adjustments are necessary to reflect the effect of our own credit quality on the fair value of our net liability position with each counterparty. This adjustment takes into account any credit enhancements, such as collateral margin we may have posted with a counterparty, as well as any letters of credit that we have provided. The methodology to determine this adjustment is consistent with how we evaluate counterparty credit risk, taking into account our own credit rating, current credit spreads, as well as any change in such spreads since the last measurement date.

Liquidity valuation adjustments are necessary when we are not able to observe a recent market price for financial instruments that trade in less active markets for the fair value to reflect the cost of exiting the position. Exchange traded contracts are valued at market value without making any additional valuation adjustments and, therefore, no liquidity reserve is applied. For contracts other than exchange traded instruments, we mark our positions to the midpoint of the bid/ask spread, and record a liquidity reserve based upon our total net position. We believe that such practice results in the most reliable fair value measurement as viewed by a market participant.

We manage our derivative instruments on a portfolio basis and the valuation adjustments described above are calculated on this basis. We believe that the portfolio level approach represents the highest and best use for these assets as there are benefits inherent in naturally offsetting positions within the portfolio at any given time, and this approach is consistent with how a market participant would view and value the assets and liabilities. Although we take a portfolio approach to managing these assets/liabilities, in order to reflect the fair value of any one individual contract within the portfolio, we allocate all valuation adjustments down to the contract level, to the extent deemed necessary, based upon either the notional contract volume, or the contract value, whichever is more applicable.

The methods described above may produce a fair value calculation that may not be indicative of net realizable value or reflective of future fair values. While we believe that our valuation methods are appropriate and consistent with other market participants, we recognize that the use of different methodologies or assumptions to determine the fair value of certain financial instruments could result in a different estimate of fair value at the reporting date. We review our fair value policies on a regular basis taking into consideration changes in the marketplace and, if necessary, will adjust our policies accordingly. See Note 11, Risk Management and Hedging Activities, Credit Risk and Financial Instruments.

Valuation Hierarchy

Our fair value measurements are grouped into a three-level valuation hierarchy. The valuation hierarchy is based upon the transparency of inputs to the valuation of an asset or liability as of the measurement date. The three levels are defined as follows:

Level 1   inputs are unadjusted quoted prices for *identical* assets or liabilities in active markets.

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Level 2 inputs include quoted prices for *similar* assets and liabilities in active markets, and inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the financial instrument.

Level 3 inputs are unobservable and considered significant to the fair value measurement.

A financial instrument s categorization within the hierarchy is based upon the input that requires the highest degree of judgment in the determination of the instrument s fair value. Following is a description of the valuation methodologies used as well as the general classification of such instruments pursuant to the hierarchy.

Commodity Derivative Assets and Liabilities

We enter into a variety of derivative financial instruments, which may include exchange traded instruments (such as New York Mercantile Exchange, or NYMEX, crude oil or natural gas futures) or over-the-counter, or OTC, instruments (such as natural gas contracts, costless collars, crude oil or NGL swaps). The exchange traded instruments are generally executed on the NYMEX exchange with a highly rated broker dealer serving as the clearinghouse for individual transactions.

Our activities expose us to varying degrees of commodity price risk. To mitigate a portion of this risk, and to manage commodity price risk related primarily to owned natural gas storage and pipeline assets, we engage in natural gas asset based trading and marketing, and we may enter into natural gas and crude oil derivatives to lock in a specific margin when market conditions are favorable. A portion of this may be accomplished through the use of exchange traded derivative contracts. Such instruments are generally classified as Level 1 since the value is equal to the quoted market price of the exchange traded instrument as of our balance sheet date, and no adjustments are required. Depending upon market conditions and our strategy we may enter into exchange traded derivative positions with a significant time horizon to maturity. Although such instruments are exchange traded, market prices may only be readily observable for a portion of the duration of the instrument. In order to calculate the fair value of these instruments, readily observable market information is utilized to the extent it is available; however, in the event that readily observable market data is not available, we may interpolate based upon observable data. In instances where we utilize an interpolated value, and it is considered significant to the valuation of the contract as a whole, we would classify the instrument within Level 2. In certain limited instances, we may extrapolate based upon the last readily observable data, developing our own expectation of fair value. To the extent that we have utilized extrapolated data, and it is considered significant to the valuation of the contract as a whole, we would classify the instrument within Level 3.

We also engage in the business of trading energy related products and services, which expose us to market variables and commodity price risk. We may enter into physical contracts or financial instruments with the objective of realizing a positive margin from the purchase and sale of these commodity-based instruments. We may enter into derivative instruments for NGLs or other energy related products, primarily using the OTC derivative instrument markets, which are not as active and liquid as exchange traded instruments. Market quotes for such contracts may only be available for short dated positions (up to six months), and an active market itself may not exist beyond such time horizon. Contracts entered into with a relatively short time horizon for which prices are readily observable in the OTC market are generally classified within Level 2. Contracts with a longer time horizon, for which we internally generate a forward curve to value such instruments, are generally classified within Level 3. The internally generated curve may utilize a variety of assumptions including, but not limited to, data obtained from third-party pricing services, historical and future expected relationship of NGL prices to crude oil prices, the knowledge of expected supply sources coming on line, expected weather trends within certain regions of the United States, and the future expected demand for NGLs.

DCP MIDSTREAM, LLC

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued

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Each instrument is assigned to a level within the hierarchy at the end of each financial quarter depending upon the extent to which the valuation inputs are observable. Generally, an instrument will move toward a level within the hierarchy that requires a lower degree of judgment as the time to maturity approaches, and as the markets in which the asset trades will likely become more liquid and prices more readily available in the market, thus reducing the need to rely upon our internally developed assumptions. However, the level of a given instrument may change, in either direction, depending upon market conditions and the availability of market observable data.

Interest Rate Derivative Assets and Liabilities

DCP Partners uses interest rate swap agreements as part of its overall capital strategy. These instruments effectively exchange a portion of DCP Partners existing floating rate debt to fixed rate debt and lock in rates on DCP Partners anticipated future fixed-rate debt. DCP Partners swaps are generally priced based upon a London Interbank Offered Rate, or LIBOR, instrument with similar duration, adjusted by the credit spread between DCP Partners and the LIBOR instrument. Given that a portion of the swap value is derived from the credit spread, which may be observed by comparing similar assets in the market, these instruments are classified within Level 2. Default risk on either side of the swap transaction is also considered in the valuation. DCP Partners records counterparty credit and entity valuation adjustments in the valuation of its interest rate swaps; however, these reserves are not considered to be a significant input to the overall valuation.

Long-Term Assets

We offer certain eligible executives the opportunity to participate in DCP Midstream LP s Non-Qualified Executive Deferred Compensation plan, and have elected to fund a portion of this participation by investing in company owned life insurance policies. These investments are reflected within our consolidated balance sheets as long-term assets and are considered financial instruments that are recorded at fair value, with any changes in fair value being recorded as a gain or loss in the consolidated statements of operations. Given that the value of these life insurance policies is determined based upon certain publicly traded mutual funds whose value is readily observable in the marketplace, these investments are classified within Level 2.

Nonfinancial Assets and Liabilities

We utilize fair value on a non-recurring basis to perform impairment tests as required on our property, plant and equipment, goodwill and intangible assets. Assets and liabilities acquired in business combinations are recorded at their fair value as of the date of acquisition. The inputs used to determine such fair value are primarily based upon internally developed cash flow models and would generally be classified within Level 3, in the event that we were required to measure and record such assets at fair value within our consolidated financial statements. Additionally, we use fair value to determine the inception value of our asset retirement obligations. The inputs used to determine such fair value are primarily based upon costs incurred historically for similar work, as well as estimates from independent third parties for costs that would be incurred to restore leased property to the contractually stipulated condition, and would generally be classified within Level 3.

We may utilize fair value on a recurring basis to measure our contingent consideration that is a result of certain acquisitions. The inputs used to determine such fair value are primarily based upon internally developed cash flow models and are classified within Level 3.

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The following table presents the financial instruments carried at fair value, by consolidated balance sheet caption and by valuation hierarchy, as described above:

	December 31, 2012				December 31, 2011			
	Level 1	Level 2	Level 3	Total Carrying Value	Level 1	Level 2	Level 3	Total Carrying Value
	(millions)							
Current assets (a):								
Commodity derivatives	$ 18	$ 23	$ 16	$ 57	$ 29	$ 55	$ 23	$ 107
Long-term assets:								
Commodity derivatives (b)	$ 2	$ 5	$ 3	$ 10	$ 11	$ 7	$ 5	$ 23
Company owned life insurance (c)	$	$ 23	$	$ 23	$	$ 18	$	$ 18
Current liabilities (d):								
Commodity derivatives	$ (13)	$ (34)	$ (14)	$ (61)	$ (36)	$ (53)	$ (8)	$ (97)
Interest rate derivatives	$	$ (4)	$	$ (4)	$	$ (16)	$	$ (16)
Long-term liabilities (e):								
Commodity derivatives	$ (3)	$ (6)	$	$ (9)	$ (6)	$ (28)	$ (1)	$ (35)
Interest rate derivatives	$	$ (2)	$	$ (2)	$	$ (5)	$	$ (5)

(a) Included in current unrealized gains on derivative instruments in our consolidated balance sheets.
(b) Included in long-term unrealized gains on derivative instruments in our consolidated balance sheets.
(c) Included in other long-term assets in our consolidated balance sheets.
(d) Included in current unrealized losses on derivative instruments in our consolidated balance sheets.
(e) Included in long-term unrealized losses on derivative instruments in our consolidated balance sheets.

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Changes in Levels 1 and 2 Fair Value Measurements

We manage our overall risk at the portfolio level, and in the execution of our strategy, we may use a combination of financial instruments, which may be classified within any level. We typically use OTC derivative contracts in order to mitigate a portion of our exposure to natural gas, NGL and condensate price changes. We also may enter into natural gas derivatives to lock in margin around our storage and transportation assets. These instruments are generally classified as Level 2. The determination to classify a financial instrument within Level 1 or Level 2 is based upon the availability of quoted prices for identical or similar assets and liabilities in active markets. Depending upon the information readily observable in the market, and/or the use of identical or similar quoted prices, which are significant to the overall valuation, the classification of any individual financial instrument may differ from one measurement date to the next. To qualify as a transfer, the asset or liability must have existed in the previous reporting period and moved into a different level during the current period. Amounts transferred in and out of Level 1 and Level 2 are reflected at fair value as of the end of the period. During the years ended December 31, 2012, 2011 and 2010, we had no transfers from Level 1 to Level 2 of the fair value hierarchy. During the years ended December 31, 2012, 2011 and 2010, we had the following transfers from Level 2 to Level 1 of the fair value hierarchy:

	Year Ended December 31,		
	2012	2011	2010
		(millions)	
Current assets	$	$	$ 1
Long-term assets	$ 1	$ 3	$ 3
Current liabilities	$	$	$
Long-term liabilities	$	$ (1)	$ (3)

These financial instruments have moved into a lower level due to the passage of time.

Changes in Level 3 Fair Value Measurements

The tables below illustrate a rollforward of the amounts included in our consolidated balance sheets for derivative financial instruments that we have classified within Level 3. The determination to classify a financial instrument within Level 3 is based upon the significance of the unobservable factors used in determining the overall fair value of the instrument. Since financial instruments classified as Level 3 typically include a combination of observable components (that is, components that are actively quoted and can be validated to external sources) and unobservable components, the gains and losses in the table below may include changes in fair value due in part to observable market factors, or changes to our assumptions on the unobservable components. Depending upon the information readily observable in the market, and/or the use of unobservable inputs, which are significant to the overall valuation, the classification of any individual financial instrument may differ from one measurement date to the next. The significant unobservable inputs used in determining fair value include adjustments by other market-based or independently sourced market data such as historical commodity volatilities, crude oil future yield curves, and/or counterparty specific considerations. In the event that there is a movement to/from the classification of an instrument as Level 3, we have reflected such items in the table below within the Transfers into Level 3 and Transfers out of Level 3 captions.

We manage our overall risk at the portfolio level, and in the execution of our strategy, we may use a combination of financial instruments, which may be classified within any level. Since Level 1 and Level 2 risk management instruments are not included in the rollforwards below, the gains or losses in the tables do not reflect the effect of our total risk management activities.

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	Commodity Derivative Instruments			
	Current Assets	Long-Term Assets (millions)	Current Liabilities	Long-Term Liabilities
Year ended December 31, 2012 (a):				
Beginning balance	$ 23	$ 5	$ (8)	$ (1)
Net realized and unrealized gains (losses) included in earnings (b)	3	(2)	(10)	1
Transfers into Level 3 (c)				
Transfers out of Level 3 (c)	(1)			
Settlements	(9)		4	
Ending balance	$ 16	$ 3	$ (14)	$
Net unrealized gains (losses) still held included in earnings (b)	$ 17	$ (2)	$ (14)	$
Year ended December 31, 2011 (a):				
Beginning balance	$ 50	$ 10	$ (45)	$ (1)
Net realized and unrealized gains (losses) included in earnings (b)	73	(5)	(56)	
Transfers into Level 3 (c)				
Transfers out of Level 3 (c)				
Settlements	(100)		93	
Ending balance	$ 23	$ 5	$ (8)	$ (1)
Net unrealized gains (losses) still held included in earnings (b)	$ 23	$ (5)	$ (8)	$

(a) There were no purchases, issuances and sales of derivatives for the years ended December 31, 2012 and 2011.
(b) Represents the amount of total gains or losses for the period, included in trading and marketing gains, net, attributable to changes in unrealized gains or losses relating to assets and liabilities classified as Level 3.
(c) Amounts transferred in and amounts transferred out are reflected at fair value as of the end of the period.

Quantitative Information and Fair Value Sensitivities Related to Level 3 Unobservable Inputs

We utilize the market approach to measure the fair value of our commodity contracts. The significant unobservable inputs used in this approach are longer dated price quotes. Our sensitivity to these longer dated forward curve prices are presented in the table below. Significant changes in any of those inputs in isolation would result in significantly different fair value measurements, depending on our short or long position in these contracts.

Product Group	Fair Value (millions)	Forward Curve Range	
Assets:			
NGLs	$ 18	$0.18 - $2.18	Per gallon
Natural Gas	1	$3.51 - $4.27	Per MMBtu (a)

Total assets	$ 19		
Liabilities:			
NGLs	$ (13)	$0.18 - $2.13	Per gallon
Natural gas	(1)	$3.51 - $4.27	Per MMBtu
Total liabilities	$ (14)		

(a) MMBtu represents one million British thermal units.

DCP MIDSTREAM, LLC

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Estimated Fair Value of Financial Instruments

Valuation of a contract s fair value is validated by an internal group independent of the marketing group. While common industry practices are used to develop valuation techniques, changes in pricing methodologies or the underlying assumptions could result in significantly different fair values and income recognition. When available, quoted market prices or prices obtained through external sources are used to determine a contract s fair value. For contracts with a delivery location or duration for which quoted market prices are not available, fair value is determined based on pricing models developed primarily from historical and expected relationship with quoted market prices.

Values are adjusted to reflect the credit risk inherent in the transaction as well as the potential impact of liquidating open positions in an orderly manner over a reasonable time period under current conditions. Changes in market prices and management estimates directly affect the estimated fair value of these contracts. Accordingly, it is reasonably possible that such estimates may change in the near term.

The fair value of our interest rate swaps and commodity non-trading derivatives is based on prices supported by quoted market prices and other external sources and prices based on models and other valuation methods. The prices supported by quoted market prices and other external sources category includes our interest rate swaps, our NGL and crude oil swaps, and our NYMEX positions in natural gas. In addition, this category includes our forward positions in natural gas for which our forward price curves are obtained from a third-party pricing service and then validated through an internal process which includes the use of independent broker quotes. This category also includes our forward positions in NGLs at points for which over-the-counter, or OTC, broker quotes for similar assets or liabilities are available for the full term of the instrument. This category also includes strip transactions whose pricing inputs are directly or indirectly observable from external sources and then modeled to daily or monthly prices as appropriate. The prices based on models and other valuation methods category includes the value of transactions for which inputs to the fair value of the instrument are unobservable in the marketplace and are considered significant to the overall fair value of the instrument. The fair value of these instruments may be based upon an internally developed price curve, which was constructed as a result of the long dated nature of the transaction or the illiquidity of the market point.

We have determined fair value amounts using available market information and appropriate valuation methodologies. However, considerable judgment is required in interpreting market data to develop the estimates of fair value. Accordingly, the estimates presented herein are not necessarily indicative of the amounts that we could realize in a current market exchange. The use of different market assumptions and/or estimation methods may have a material effect on the estimated fair value amounts.

The fair value of accounts receivable, accounts payable and short-term borrowings are not materially different from their carrying amounts because of the short-term nature of these instruments or the stated rates approximating market rates. Derivative instruments are carried at fair value. As of December 31, 2012, the carrying and fair value of our long-term debt, including current maturities of long-term debt, was $4,693 million and $5,236 million, respectively. As of December 31, 2011, the carrying and fair value of our long-term debt was $3,820 million and $4,264 million, respectively. We determine the fair value of our variable rate debt based upon the discounted present value of expected future cash flows, taking into account the difference between the contractual borrowing spread and the spread for similar credit facilities available in the marketplace. We determine the fair value of our fixed-rate debt based on quotes obtained from bond dealers. We classify the fair value of our outstanding debt balances within Level 2 of the fair value hierarchy.

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DCP MIDSTREAM, LLC

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10. Financing

	December 31, 2012	December 31, 2011
	(millions)	
Short-term borrowings	$ 958	$ 370
DCP Midstream s debt securities:		
Issued November 2008, interest at 9.700% payable semiannually, due December 2013	250	250
Issued October 2005, interest at 5.375% payable semiannually, due October 2015	200	200
Issued February 2009, interest at 9.750% payable semiannually, due March 2019	450	450
Issued March 2010, interest at 5.350% payable semiannually, due March 2020	600	600
Issued September 2011, interest at 4.750% payable semiannually, due September 2021	500	500
Issued August 2000, interest at 8.125% payable semiannually, due August 2030 (a)	300	300
Issued October 2006, interest at 6.450% payable semiannually, due November 2036	300	300
Issued September 2007, interest at 6.750% payable semiannually, due September 2037	450	450
DCP Partners debt securities:		
Issued September 2010, interest at 3.25% payable semiannually, due October 2015	250	250
Issued November 2012, interest at 2.50% payable semiannually, due December 2017	500	
Issued March 2012, interest at 4.95% payable semiannually, due April 2022	350	
DCP Partners revolving credit facility, weighted-average variable interest rate of 1.47% and 1.69%, respectively, due November 2016 (b)	525	497
Fair value adjustments related to interest rate swap fair value hedges (a)	32	34
Unamortized discount	(14)	(11)
Total debt	5,651	4,190
Current maturities of long-term debt	(250)	
Short-term borrowings	(958)	(370)
Total long-term debt	$ 4,443	$ 3,820

(a) In December 2008, the swaps associated with this debt were terminated. The remaining long-term fair value of approximately $32 million related to the swaps is being amortized as a reduction to interest expense through the maturity date of the debt.

(b) $150 million has been swapped to a fixed interest rate obligation with effective fixed interest rates ranging from 2.94% to 2.99%, for a net effective interest rate of 2.25% on the $525 million of outstanding debt under DCP Partners revolving credit facility as of December 31, 2012. $450 million of debt was swapped to a fixed-rate obligation with effective interest rates ranging from 2.94% to 5.19%, for a net effective rate of 4.86% on the $497 million of outstanding debt under the DCP Partners revolving credit facility as of December 31, 2011.

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DCP MIDSTREAM, LLC

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Approximate future maturities of long-term debt in the year indicated are as follows at December 31, 2012:

	Debt Maturities (millions)
2013	$ 250
2014	
2015	450
2016	525
2017	500
Thereafter	2,950
	4,675
Fair value adjustments related to interest rate swap fair value hedges	32
Unamortized discount	(14)
Current maturities of long-term debt	(250)
Long-term debt	$ 4,443

DCP Midstream s Debt Securities In September 2011, we issued $500 million principal amount of 4.75% Senior Notes due September 30, 2021, or the 4.75% Notes, for proceeds of approximately $496 million, net of unamortized discounts and related offering costs. We will pay interest semiannually on March 30 and September 30 of each year, and our first payment occurred on March 30, 2012. The underwriters fees and related expenses are deferred in other long-term assets in the consolidated balance sheets and will be amortized over the term of the notes. The net proceeds from this offering were used to repay short-term borrowings and for general corporate purposes.

In March 2010, we issued $600 million principal amount of 5.35% Senior Notes due 2020, or the 5.35% Notes, for proceeds of approximately $597 million, net of unamortized discounts and related offering costs. The 5.35% Notes mature and become due and payable on March 15, 2020. We pay interest semiannually on March 15 and September 15 of each year, and our first payment was on September 15, 2010. The net proceeds from this offering were used to repay a portion of our $800 million, 7.875% Notes that were due August 2010, and for general corporate purposes.

The DCP Midstream debt securities mature and become payable on the respective due dates, and are not subject to any sinking fund provisions. The DCP Midstream debt securities are senior unsecured obligations, and are redeemable at a premium at our option.

DCP Midstream s Credit Facilities with Financial Institutions On March 2, 2012, we entered into a $2 billion revolving credit facility, or the $2 Billion Facility, which matures in March 2017 and terminated our existing $1,250 million revolving credit facility which would have matured in March 2015 and our existing $450 million revolving credit facility which would have matured in April 2012, or together the $1.7 Billion Facilities. The $2 Billion Facility allows for up to two one-year extensions of the March 2017 maturity date, subject to lender consent. There were no borrowings outstanding under the $2 Billion Facility as of December 31, 2012.

The $2 Billion Facility may be used to support our commercial paper program, our capital expansion program, working capital requirements and other general corporate purposes as well as for letters of credit, up to a maximum of $200 million of outstanding letters of credit. As of December 31, 2012 and 2011, we had $958 million and $370 million of commercial paper outstanding, backed by the $2 Billion Facility and the $1.7 Billion

DCP MIDSTREAM, LLC

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS   Continued

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Facilities, respectively, which are included in short-term borrowings in our consolidated balance sheets. As of December 31, 2012 and 2011, we had $6 million and $7 million, respectively, in letters of credit outstanding. As of December 31, 2012, the available capacity under the $2 Billion Facility was $1,036 million.

On March 2, 2012, we entered into a $1 billion delayed draw term loan agreement, or the Term Loan, which matures in September 2014. Proceeds from the Term Loan may be used for our capital expansion program and working capital requirements. On November 15, 2012, we repaid $250 million of outstanding borrowings under the Term Loan with proceeds from the sale of a one-third interest in Sand Hills and Southern Hills to both Spectra Energy and Phillips 66, as required by the Term Loan agreement. Under the Term Loan agreement, amounts repaid on the Term Loan may not be reborrowed, as such; the Term Loan capacity has been reduced to approximately $750 million as of December 31, 2012. As of December 31, 2012, there were no borrowings outstanding under the Term Loan.

As of December 31, 2012, the unused capacity under the $2 Billion Facility and Term Loan was $1,786 million, of which approximately $960 million was available for general working capital purposes. Our borrowing capacity is limited at December 31, 2012 by the $2 Billion Facility and Term Loan s financial covenant requirements.

The $2 Billion Facility bears interest at either: (1) LIBOR, plus an applicable margin of 1.175% based on our current credit rating; or (2) (a) the base rate which shall be the higher of Wells Fargo Bank N.A. s prime rate, the Federal Funds rate plus 0.50% or the LIBOR Market Index rate plus 1% plus (b) an applicable margin of 0.175% based on our current credit rating. The $2 Billion Facility incurs an annual facility fee of 0.20% based on our current credit rating. This fee is paid on drawn and undrawn portions of the $2 Billion Facility.

The Term Loan bears interest at either: (1) LIBOR, plus an applicable margin of 1.375% based on our current credit rating; or (2) (a) the base rate which shall be the higher of Royal Bank of Canada s prime rate, the Federal Funds rate plus 0.50% or the LIBOR Market Index rate plus 1% plus (b) an applicable margin of 0.375% based on our current credit rating. The Term Loan incurs an annual commitment fee of 0.20% based on our current credit rating. This fee is paid on undrawn portions of the Term Loan.

The $2 Billion Facility and the Term Loan requires us to maintain a consolidated leverage ratio (the ratio of consolidated indebtedness to consolidated EBITDA as defined) of not more than 5.0 to 1.0, and following the consummation of qualifying acquisitions (as defined), not more than 5.5 to 1.0, on a temporary basis for three consecutive quarters, including the quarter in which such acquisition is consummated. Any drawn amounts under the Term Loan are required to be repaid from proceeds from the sale or contribution of Sand Hills or Southern Hills. Commencing with the fiscal period ending December 31, 2012 and continuing through the fiscal period ending December 31, 2013, the definition of consolidated EBITDA under the $2 Billion Facility and the Term Loan has been amended to allow for additional adjustments related to certain projects.

DCP Partners Debt Securities   On November 27, 2012, DCP Partners issued $500 million of 2.50% 5-year Senior Notes, or the DCP Partners 2.50% Notes, due December 1, 2017. DCP Partners received net proceeds of $494 million, net of underwriters fees, related expenses and unamortized discounts. Interest on the notes will be paid semiannually on June 1 and December 1 of each year, commencing June 1, 2013. The underwriters fees and related expenses are deferred in other long-term assets in the consolidated balance sheets and will be amortized over the term of the notes.

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On March 13, 2012, DCP Partners issued $350 million of 4.95% 10-year Senior Notes, or the DCP Partners 4.95% Notes, due April 1, 2022. DCP Partners received proceeds of $346 million, net of underwriters fees, related expenses and unamortized discounts, which were used to fund the cash portion of DCP Partners acquisition of our 66.67% remaining interest in Southeast Texas and to repay funds borrowed under DCP Partners Credit Agreement and the DCP Partners Term Loan. Interest on the notes will be paid semiannually on April 1 and October 1 of each year, and DCP Partners first payment occurred on October 1, 2012. The underwriters fees and related expenses are deferred in other long-term assets in the consolidated balance sheets and will be amortized over the term of the notes.

In September 2010, DCP Partners issued $250 million of 3.25% Senior Notes, or the DCP Partners 3.25% Notes, due October 1, 2015, for proceeds of approximately $248 million, which are net of unamortized discounts and related offering costs. The DCP Partners 3.25% Notes mature and become due and payable on October 1, 2015, unless redeemed prior to maturity. DCP Partners pays interest semiannually on April 1 and October 1 of each year, with the first payment made on April 1, 2011. The net proceeds from this offering were used to repay funds borrowed under the revolver portion of the DCP Partners Credit Facility.

DCP Partners debt securities mature and become payable on the respective due dates, unless redeemed prior to maturity, and are not subject to any sinking fund provisions. DCP Partners debt securities are senior unsecured obligations, and are redeemable at a premium at DCP Partners option.

DCP Partners Credit Facilities with Financial Institutions On November 2, 2012, DCP Partners entered into a 2-year term loan agreement, or the $344 Million Term Loan, and borrowed $344 million to fund the cash portion of the acquisition of a 33.33% interest in the Eagle Ford System. On July 2, 2012, DCP Partners entered into a 2-year term loan agreement, or the $140 Million Term Loan, and borrowed $140 million to fund the cash portion of its acquisition of the Mont Belvieu Fractionators. In November 2012, DCP Partners repaid both term loans with proceeds from the DCP Partners 2.50% Notes.

On January 3, 2012, DCP Partners entered into a 2-year term loan agreement and borrowed $135 million, which was used to fund a portion of DCP Partners acquisition of our remaining 49.9% interest in East Texas. In March 2012, DCP Partners repaid this term loan with proceeds from the DCP Partners 4.95% Notes.

DCP Partners has a $1 billion revolving credit facility, or the DCP Partners Credit Agreement, that matures November 10, 2016. As of both December 31, 2012 and 2011, DCP Partners had $1 million of letters of credit issued under the DCP Partners Credit Agreement. As of December 31, 2012, the unused capacity under the revolving credit facility was $474 million, which was available for general working capital purposes. DCP Partners borrowing capacity is limited at December 31, 2012 by DCP Partners Credit Agreement s financial covenant requirements.

The DCP Partners Credit Agreement bears interest at either: (1) LIBOR, plus an applicable margin of 1.25% based on DCP Partners current credit rating; or (2) (a) the base rate which shall be the higher of Wells Fargo Bank N.A. s prime rate, the Federal Funds rate plus 0.50% or the LIBOR Market Index rate plus 1% plus (b) an applicable margin of 0.25% based on DCP Partners current credit rating. The revolving credit facility incurs an annual facility fee of 0.25% based on DCP Partners current credit rating. This fee is paid on drawn and undrawn portions of the revolving credit facility.

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The DCP Partners Credit Agreement requires DCP Partners to maintain a leverage ratio (the ratio of DCP Partners consolidated indebtedness to DCP Partners consolidated EBITDA, in each case as is defined by the Credit Agreement) of not more than 5.0 to 1.0, and following the consummation of qualifying acquisitions (as defined by the DCP Partners Credit Agreement), not more than 5.5 to 1.0, on a temporary basis for three consecutive quarters, including the quarter in which such acquisition is consummated.

Other Agreements DCP Partners had a contingent letter of credit facility for up to $10 million, which expired in July 2012.

Other Financing During the year ended December 31, 2012, DCP Partners issued 1,147,654 of its common units, under an on-going equity distribution agreement with a financial institution and received proceeds of $47 million, net of commissions and offering costs.

In July 2012, DCP Partners closed a private placement of equity with a group of institutional investors in which DCP Partners sold 4,989,802 of its common units at a price of $35.55 per unit and received proceeds of $174 million, net of offering costs.

In March 2012, DCP Partners issued 5,148,500 of its common units at $47.42 per unit. DCP Partners received proceeds of $234 million, net of offering costs.

During 2011, DCP Partners issued 761,285 of its common units, under an on-going equity distribution agreement with Citigroup Global Markets Inc., and received proceeds from units issued of $30 million, net of commissions and offering costs.

In March 2011, DCP Partners issued 3,596,636 common units at $40.55 per unit. DCP Partners received proceeds of $140 million, net of offering costs.

In November 2010, DCP Partners issued 2,875,000 common units at $34.96 per unit. DCP Partners received proceeds of $96 million, net of offering costs.

In August 2010, DCP Partners issued 2,990,000 common units at $32.57 per unit. DCP Partners received proceeds of $93 million, net of offering costs.

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

Our day-to-day operations expose us to a variety of risks including but not limited to changes in the prices of commodities that we buy or sell, changes in interest rates, and the creditworthiness of each of our counterparties. We manage certain of these exposures by using physical and financial derivative instruments. All of our commodity derivative activities are conducted under the governance of internal Risk Management Committees that establish policies limiting exposure to market risk and requiring daily reporting to management of potential financial exposure. These policies include statistical risk tolerance limits using historical price movements to calculate daily value at risk. The following briefly describes each of the risks that we manage.

Commodity Price Risk

Our portfolio of commodity derivative activity is primarily accounted for using the mark-to-market method of accounting; however, depending upon our risk profile and objectives, in certain limited cases, we may execute transactions that qualify for the hedge method of accounting. The risks, strategies and instruments used to mitigate such risks, as well as the method of accounting are discussed and summarized below.

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Natural Gas Asset Based Trading and Marketing

Our natural gas asset based trading and marketing activities engage in the business of trading energy related products and services, including managing purchase and sales portfolios, storage contracts and facilities, and transportation commitments for products. These energy trading operations are exposed to market variables and commodity price risk with respect to these products and services, and we may enter into physical contracts and financial instruments with the objective of realizing a positive margin from the purchase and sale of commodity-based instruments. We manage commodity price risk related to our natural gas storage and pipeline assets by engaging in natural gas asset based trading and marketing. The commercial activities related to our natural gas asset based trading and marketing primarily consist of time spreads and basis spreads.

We may execute a time spread transaction when the difference between the current price of natural gas (cash or futures) and the futures market price for natural gas exceeds our cost of storing physical gas in our owned and/or leased storage facilities. The time spread transaction allows us to lock in a margin when this market condition exists. A time spread transaction is executed by establishing a long gas position at one point in time and establishing an equal short gas position at a different point in time. We typically use swaps to execute these transactions, which are not designated as hedging instruments and are recorded at fair value with changes in fair value recorded in the current period consolidated statements of operations. While gas held in our storage locations is recorded at the lower of average cost or market, the derivative instruments that are used to manage our storage facilities are recorded at fair value and any changes in fair value are currently recorded in our consolidated statements of operations. Even though we may have economically hedged our exposure and locked in a future margin, the use of lower-of-cost-or-market accounting for our physical inventory and the use of mark-to-market accounting for our derivative instruments may subject our earnings to market volatility.

We may execute basis spread transactions when the market price differential between locations on a pipeline asset exceeds our cost of transporting physical gas through our owned and/or leased pipeline asset. When this market condition exists, we may execute derivative instruments around this differential at the market price. This basis spread transaction allows us to lock in a margin on our physical purchases and sales of gas. We typically use swaps to execute these transactions, which are not designated as hedging instruments and are recorded at fair value with changes in fair value recorded in the current period consolidated statements of operations. As discussed above, the accounting for physical gas purchases and sales and the accounting for the derivative instruments used to manage such purchases and sales differ, and may subject our earnings to market volatility, even though the transaction represents an economic hedge in which we have locked in a future margin.

In order for our storage facility to remain operational, a minimum level of base gas must be maintained in each storage cavern, which is capitalized on our consolidated balance sheets as a component of property, plant and equipment, net. During 2011, we commenced an expansion project to build an additional storage cavern. Upon completion of the expansion project, we will be required to purchase a significant amount of base gas to bring the storage cavern to operation. To mitigate risk associated with the forecasted purchase of natural gas in June, July and August 2013, we executed a series of derivative financial instruments, which have been designated as cash flow hedges. These cash flow hedges were in a loss position of $3 million as of December 31, 2012, and will fluctuate in value through the term of construction. Any effective changes in fair value of these derivative instruments will be deferred in AOCI until the underlying purchase of inventory occurs. While the cash paid or received upon settlement of these hedges will economically offset the cash required to purchase the base gas, following completion of the additional storage cavern, any deferred gain or loss at the time of the purchase will remain in AOCI until the cavern is emptied and the base gas is sold. As of December 31, 2012, there was a deferred loss of $3 million recognized in AOCI in relation to our 2009 storage cavern expansion, and will remain in AOCI until such time that the cavern is emptied and the base gas is sold.

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NGL Proprietary Trading

Our NGL proprietary trading activity includes trading energy related products and services. We undertake these activities through the use of fixed forward sales and purchases, basis and spread trades, storage opportunities, put/call options, term contracts and spot market trading. These energy trading operations are exposed to market variables and commodity price risk with respect to these products and services, and these operations may enter into physical contracts and financial instruments with the objective of realizing a positive margin from the purchase and sale of commodity-based instruments. These physical and financial instruments are not designated as hedging instruments and are recorded at fair value with changes in fair value recorded in the current period consolidated statements of operations.

We employ established risk limits, policies and procedures to manage risks associated with the natural gas asset based trading and marketing and NGL proprietary trading.

Commodity Cash Flow Protection Activities at DCP Partners

As a result of DCP Partners operations of gathering, processing and transporting natural gas, DCP Partners takes title to a portion of residue gas, NGLs and condensate, which are considered to be DCP Partners equity volumes. The possession of and the related operations of transporting and marketing of these commodities creates commodity price risk due to market changes in commodity prices, primarily with respect to the prices of NGLs, natural gas and crude oil. DCP Partners has mitigated a portion of its expected commodity cash flow risk associated with these equity volumes through 2016 with commodity derivative instruments. DCP Partners commodity derivative instruments used for its hedging program are a combination of direct NGL product, crude oil and natural gas hedges. Due to the limited depth of the NGL derivatives market, DCP Partners has used crude oil swaps and costless collars to mitigate a portion of its commodity price risk exposure for NGLs. Prices of NGLs have generally been related to the price of crude oil, however, there are some periods of time when NGL pricing may be at a greater discount to crude oil pricing, resulting in additional exposure to NGL commodity prices. During 2012, the relationship of NGLs to crude oil has been lower than historical relationships, however, a significant amount of DCP Partners NGL hedges from 2012 through 2015 are direct product hedges. When crude oil swaps become short-term in nature, DCP Partners may periodically convert certain crude oil derivatives to NGL derivatives by entering into offsetting crude oil swaps while adding NGL swaps. These transactions are primarily accomplished through the use of forward contracts that exchange DCP Partners floating price risk for a fixed price. DCP Partners also utilizes costless collars that minimize its floating price risk by establishing a fixed price floor and a fixed price ceiling. However, the type of instrument that DCP Partners uses to mitigate a portion of its risk may vary depending on DCP Partners risk management objective. These transactions are not designated as hedging instruments for accounting purposes and the change in fair value is reflected in the current period within our consolidated statements of operations.

Interest Rate Risk

We enter into debt arrangements that have either fixed or floating rates, therefore we are exposed to market risks related to changes in interest rates. We periodically use interest rate swaps to convert variable interest rates to fixed rates on our existing debt and to lock in rates on our anticipated future fixed-rate debt, respectively. Our primary goals include: (1) maintaining an appropriate ratio of fixed-rate debt to floating-rate debt; (2) reducing volatility of earnings resulting from interest rate fluctuations; and (3) locking in attractive interest rates.

DCP MIDSTREAM, LLC

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DCP Partners mitigates a portion of its interest rate risk with interest rate swaps, which reduce DCP Partners exposure to market fluctuations by converting variable interest rates on DCP Partners existing debt to fixed interest rates. The interest rate swap agreements convert the interest rate associated with the indebtedness outstanding under DCP Partners revolving credit facility to a fixed-rate obligation, thereby reducing the exposure to market rate fluctuations.

At December 31, 2011, DCP Partners had interest rate swap agreements totaling $450 million, of which DCP Partners had designated $425 million as cash flow hedges and accounted for the remaining $25 million under the mark-to-market method of accounting. In March 2012, DCP Partners paid down a portion of the DCP Partners Credit Agreement. As a result of the pay down of the DCP Partners Credit Agreement, DCP Partners discontinued cash flow hedge accounting on $225 million of its interest rate swap agreements. $300 million of swap agreements settled in the second quarter of 2012.

At December 31, 2012, DCP Partners had interest rate swap agreements extending through June 2014 totaling $150 million, which DCP Partners has designated as cash flow hedges. At December 31, 2012, $150 million of the agreements reprice prospectively approximately every 30 days. Under the terms of the interest rate swap agreements, DCP Partners pays fixed-rates ranging from 2.94% to 2.99%, and receives interest payments based on the one-month LIBOR.

Effectiveness of DCP Partners interest rate swap agreements designated as cash flow hedges is determined by matching the principal balance and terms with that of the specified obligation. The effective portions of changes in fair value are recognized in AOCI in the consolidated balance sheets and are reclassified into earnings as the hedged transactions impacted earnings. However, due to the volatility of the interest rate markets, the corresponding value in AOCI is subject to change prior to its reclassification into earnings. Ineffective portions of changes in fair value are recognized in earnings.

In March 2012, DCP Partners settled $195 million of its forward-starting interest rate swap agreements for $7 million. The remaining net deferred losses of $5 million in AOCI will be amortized into interest expense associated with DCP Partners long-term debt through 2022.

We previously had interest rate cash flow hedges and fair value hedges in place that were terminated in 2000 and 2008, respectively. As a result, the remaining net loss deferred in AOCI relative to these cash flow hedges and the remaining net loss included in long-term debt relative to these fair value hedges will be reclassified to interest expense through the remaining term of the debt through 2030, as the underlying transactions impact earnings.

Credit Risk

Our principal customers range from large, natural gas marketing services to industrial end-users for our natural gas products and services, as well as large multi-national petrochemical and refining companies, to small regional propane distributors for our NGL products and services. Substantially all of our natural gas and NGL sales are made at market-based prices. Approximately 40% of our NGL production is committed to Phillips 66 (or ConocoPhillips prior to May 1, 2012) and CP Chem, both related parties, under an existing 15-year contract, the primary production commitment of which expires in 2015. This concentration of credit risk may affect our overall credit risk, in that these customers may be similarly affected by changes in economic, regulatory or other factors. Where exposed to credit risk, we analyze the counterparties financial condition prior to entering into an agreement, establish credit limits and monitor the appropriateness of these limits on an ongoing basis. We may

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use various master agreements that include language giving us the right to request collateral to mitigate credit exposure. The collateral language provides for a counterparty to post cash or letters of credit for exposure in excess of the established threshold. The threshold amount represents an open credit limit, determined in accordance with our credit policy. The collateral language also provides that the inability to post collateral is sufficient cause to terminate a contract and liquidate all positions. In addition, our master agreements and our standard gas and NGL sales contracts contain adequate assurance provisions, which allow us to suspend deliveries and cancel agreements, or continue deliveries to the buyer after the buyer provides security for payment in a satisfactory form.

Contingent Credit Features

Each of the above risks is managed through the execution of individual contracts with a variety of counterparties. Certain of our derivative contracts may contain credit-risk related contingent provisions that may require us to take certain actions in certain circumstances.

We have International Swap Dealers Association, or ISDA, contracts which are standardized master legal arrangements that establish key terms and conditions which govern certain derivative transactions. These ISDA contracts contain standard credit-risk related contingent provisions. Some of the provisions we are subject to are outlined below.

- In the event that we or DCP Partners were to be downgraded below investment grade by at least one of the major credit rating agencies, certain of our ISDA counterparties have the right to reduce our collateral threshold to zero, potentially requiring us to fully collateralize any commodity contracts in a net liability position.

- In some cases, our ISDA contracts contain cross-default provisions that could constitute a credit-risk related contingent feature. For example, if we were to fail to make a required interest or principal payment on a debt instrument, above a predefined threshold level, and after giving effect to any applicable notice or grace period as defined in the ISDA contracts, our ISDA counterparties may have the right to request early termination and net settlement of any outstanding derivative positions.

Depending upon the movement of commodity prices and interest rates, each of our individual contracts with counterparties to our commodity derivative instruments or interest rate swap instruments are in either a net asset or net liability position. Our commodity derivative contracts that are not governed by ISDA contracts do not have any credit-risk related contingent features. As of December 31, 2012, we had $23 million of individual commodity derivative contracts that contain credit-risk related contingent features that were in a net liability position, and have not posted any cash collateral relative to such positions. If a credit-risk related event were to occur and we were required to net settle our position with an individual counterparty, our ISDA contracts permit us to net all outstanding contracts with that counterparty, whether in a net asset or net liability position, as well as any cash collateral already posted. As of December 31, 2012, if a credit-risk related event were to occur, we may be required to post additional collateral. Although our commodity derivative contracts that contain credit-risk related contingent features were in a net liability position as of December 31, 2012, if a credit-risk related event were to occur, the net liability position would be partially offset by contracts in a net asset position reducing our net liability to $21 million.

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As of December 31, 2012, DCP Partners had $150 million of individual interest rate swap instruments that were in a net liability position of $6 million and were subject to credit-risk related contingent features. If DCP Partners were to have an event of default relative to any covenants of the DCP Partners Credit Agreement, that occurs and is continuing, the counterparties to DCP Partners swap instruments have the right to request that DCP Partners net settle the instrument in the form of cash.

Collateral

As of December 31, 2012, we held cash of less than $1 million, included in other current liabilities in the consolidated balance sheet related to cash postings by third parties, and letters of credit of $72 million from counterparties to secure their future performance under financial or physical contracts. We had cash deposits with counterparties of $17 million included in other current assets as of December 31, 2012, to secure our obligations to provide future services or to perform under financial contracts. As of December 31, 2012, DCP Partners had no cash collateral posted with counterparties to its commodity derivative instruments. As of December 31, 2012, we had issued and outstanding parental guarantees totaling $25 million in favor of certain counterparties to DCP Partners commodity derivative instruments to mitigate a portion of DCP Partners collateral requirements with those counterparties. DCP Partners pays us a fee of 0.50% per annum on these guarantees. These parental guarantees reduce the amount of cash DCP Partners may be required to post as collateral. Collateral amounts held or posted may be fixed or may vary, depending on the value of the underlying contracts, and could cover normal purchases and sales, trading and hedging contracts. In many cases, we and our counterparties publicly disclose credit ratings, which may impact the amounts of collateral requirements.

Physical forward contracts and financial derivatives are generally cash settled at the expiration of the contract term. These transactions are generally subject to specific credit provisions within the contracts that would allow the seller, at its discretion, to suspend deliveries, cancel agreements or continue deliveries to the buyer after the buyer provides security for payment satisfactory to the seller.

Summarized Derivative Information

The following summarizes the balance within AOCI, net of noncontrolling interest, relative to our commodity and interest rate cash flow hedges:

	December 31, 2012	December 31, 2011
	(millions)	
Commodity cash flow hedges:		
Net deferred losses in AOCI	$ (5)	$ (5)
Interest rate cash flow hedges:		
Net deferred losses in AOCI	(4)	(7)
Total AOCI	$ (9)	$ (12)

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The fair value of our derivative instruments that are designated as hedging instruments and those that are marked-to-market each period, and the location of each within our consolidated balance sheets, by major category, is summarized as follows:

Balance Sheet Line Item	December 31, 2012 (millions)	December 31, 2011 (millions)	Balance Sheet Line Item	December 31, 2012 (millions)	December 31, 2011 (millions)
Derivative Assets Designated as Hedging Instruments:			**Derivative Liabilities Designated as Hedging Instruments:**		
Interest rate derivatives:			**Interest rate derivatives:**		
Unrealized gains on derivative instruments current	$	$	Unrealized losses on derivative instruments current	$ (4)	$ (16)
Unrealized gains on derivative instruments long-term			Unrealized losses on derivative instruments long-term	(2)	(5)
	$	$		$ (6)	$ (21)
Commodity derivatives:			**Commodity derivatives:**		
Unrealized gains on derivative instruments current	$	$	Unrealized losses on derivative instruments current	$ (3)	$
Unrealized gains on derivative instruments long-term			Unrealized losses on derivative instruments long-term		(3)
	$	$		$ (3)	$ (3)
Derivative Assets Not Designated as Hedging Instruments:			**Derivative Liabilities Not Designated as Hedging Instruments:**		
Commodity derivatives:			**Commodity derivatives:**		
Unrealized gains on derivative instruments current	$ 57	$ 107	Unrealized losses on derivative instruments current	$ (58)	$ (97)
Unrealized gains on derivative instruments long-term	10	23	Unrealized losses on derivative instruments long-term	(9)	(32)
	$ 67	$ 130		$ (67)	$ (129)

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The following table summarizes the impact on our consolidated balance sheets and consolidated statements of operations of our derivative instruments, net of noncontrolling interest, that are accounted for using the cash flow hedge method of accounting for each of the years ended December 31, 2012 and 2011:

	Loss Recognized in AOCI on Derivatives Effective Portion		Loss Reclassified from AOCI to Earnings Effective Portion		Gain (Loss) Recognized in Income on Derivatives Ineffective Portion and Amount Excluded from Effectiveness Testing		Deferred Losses in AOCI Expected to be Reclassified into Earnings Over the Next 12 Months
	2012	2011	2012	2011	2012	2011	
			(millions)				(millions)
Commodity derivatives	$ (1)	$ (2)	$ (1)	$	$	$	$
Interest rate derivatives	$	$ (3)	$ (3)	$ (6)(a)	$	$ (a)(b)	$ (1)

(a) Included in interest expense in our consolidated statements of operations.

(b) For the years ended December 31, 2012 and 2011, no derivative gains or losses were reclassified from AOCI to current period earnings as a result of the discontinuance of cash flow hedges related to certain forecasted transactions that are not probable of occurring or as a result of exclusion from effectiveness testing.

Change in value of derivative instruments, for which the hedge method of accounting has not been elected from one period to the next, are recorded in the consolidated statements of operations. The following summarizes these amounts and the location within the consolidated statements of operations that such amounts are reflected:

Commodity Derivatives: Statement of Operations Line Item	2012	Year Ended December 31, 2011	2010
		(millions)	
Realized gains	$ 86	$ 28	$ 118
Unrealized gains (losses)		50	(74)
Trading and marketing gains, net	$ 86	$ 78	$ 44

We do not have any derivative financial instruments that qualify as a hedge of a net investment.

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The following tables represent, by commodity type, our net long or short derivative positions, as well as the number of outstanding contracts that are expected to partially or entirely settle in each respective year. To the extent that we have long dated derivative positions that span multiple calendar years, the contract will appear in more than one line item in the table below. Additionally, relative to the hedging of certain of our storage and/or transportation assets, we may execute basis transactions for natural gas, which may result in a net long/short position of zero. This table also presents our net long or short natural gas basis swap positions separately from our net long or short natural gas positions.

	December 31, 2012							
	Crude Oil		Natural Gas		Natural Gas Liquids		Natural Gas Basis Swaps	
Year of Expiration	Net Short Position (Bbls) (a)	Number of Contracts	Net Short Position (MMBtu)	Number of Contracts	Net Short Position (Bbls)	Number of Contracts	Net Short Position (MMBtu)	Number of Contracts
2013	(1,139,514)	478	(18,670,425)	239	(12,966,380)	410(b)	(1,615,000)	132
2014	(825,500)	119	(365,000)	3	(8,910,000)	4(c)	(1,350,000)	4
2015	(293,000)	13						
2016	(183,000)	1						

(a) Bbls represents barrels.
(b) Includes 34 physical index based derivative contracts totaling (13,612,800) Bbls.
(c) Includes 2 physical index based derivative contracts totaling (9,000,000) Bbls.

	December 31, 2011							
	Crude Oil		Natural Gas		Natural Gas Liquids		Natural Gas Basis Swaps	
Year of Expiration	Net Long (Short) Position (Bbls)	Number of Contracts	Net Long (Short) Position (MMBtu)	Number of Contracts	Net Long (Short) Position (Bbls)	Number of Contracts	Net Long (Short) Position (MMBtu)	Number of Contracts
2012	(1,161,792)	488	(19,768,750)	203	(10,987,055)	427(a)	10,012,500	190
2013	(797,323)	207	1,835,000	8	(8,966,650)	15(b)	120,000	22
2014	(619,500)	44	(365,000)	3	(9,000,000)	2(c)		
2015	(365,000)	2						
2016	(183,000)	1						

(a) Includes 22 physical index based derivative contracts totaling (11,751,600) barrels, or Bbls.
(b) Includes 3 physical index based derivative contracts totaling (9,036,000) Bbls.
(c) Includes 2 physical index based derivative contracts totaling (9,000,000) Bbls.

As of December 31, 2012, DCP Partners had interest rate swaps outstanding with individual notional values of $70 million and $80 million, which, in aggregate, exchange up to $150 million of DCP Partners floating rate obligation for a fixed rate obligation through June 2014.

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12. Equity-Based Compensation

We recorded equity-based compensation expense as follows, the components of which are further described below:

	Year Ended December 31, 2012	2011 (millions)	2010
DCP Midstream, LLC Long-Term Incentive Plan	$ 14	$ 25	$ 12
DCP Partners Long-Term Incentive Plan (DCP Partners LTIP)	2	6	3
Total	$ 16	$ 31	$ 15

	Vesting Period (years)	Unrecognized Compensation Expense at December 31, 2012 (millions)		Estimated Forfeiture Rate	Weighted-Average Remaining Vesting (years)
DCP Midstream LTIP:					
Relative Performance Units (RPUs)	3	$			
Strategic Performance Units (SPUs)	3	$	8	15% - 28%	2
Phantom Units	3	$	4	0% - 28%	1
DCP Partners Phantom Units	3	$		28%	1
DCP Partners LTIP:					
Performance Phantom Units	3	$		20 - 30%	2
Phantom Units	0.5	$			
Restricted Phantom Units	1-3	$		20 - 30%	2

DCP Midstream LTIP Under the DCP Midstream LTIP, awards may be granted to our key employees. The DCP Midstream LTIP provides for the grant of Relative Performance Units, or RPUs, Strategic Performance Units, or SPUs, and Phantom Units. The RPUs, SPUs and Phantom Units consist of a notional unit based on the value of common shares or units of ConocoPhillips, Phillips 66, Spectra Energy and DCP Partners. The DCP Partners Phantom Units constitute a notional unit equal to the fair value of DCP Partners common units. Each award provides for the grant of dividend or distribution equivalent rights, or DERs. The LTIP is administered by the compensation committee of our board of directors. All awards are subject to cliff vesting.

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Relative Performance Units The number of RPUs that will ultimately vest range, in value up to 200% of the outstanding RPUs, depending on the achievement of specified performance targets over a three year period. The final performance payout is determined by the compensation committee of our board of directors. After the performance period the value derived from the RPUs is transferred to our Non-Qualified Deferred Compensation plan, and invested according to the participant s investment elections. The DERs are paid in cash at the end of the performance period. The following tables presents information related to RPUs:

	Units	Grant Date Weighted-Average Price Per Unit	Measurement Date Weighted-Average Price Per Unit
Outstanding at January 1, 2010	25,040	$ 44.02	
Transferred to Non-Qualified Executive Deferred Compensation Plan (a)	(25,040)	$ 44.02	
Outstanding at December 31, 2012, 2011 and 2010		$	$

(a) Units vesting in 2010 transferred at 100%.

Strategic Performance Units The number of SPUs that will ultimately vest range, in value up to 200% of the outstanding SPUs, depending on the achievement of specified performance targets over a three year period. The final performance payout is determined by the compensation committee of our board of directors. The DERs are paid in cash at the end of the performance period. The following tables presents information related to SPUs:

	Units	Grant Date Weighted-Average Price Per Unit	Measurement Date Weighted-Average Price Per Unit
Outstanding at January 1, 2010	374,917	$ 27.48	
Granted	139,900	$ 30.03	
Forfeited	(7,710)	$ 26.79	
Vested or paid in cash (b)	(166,237)	$ 41.59	
Outstanding at December 31, 2010	340,870	$ 21.66	
Granted	122,020	$ 38.59	
Forfeited	(5,786)	$ 27.15	
Vested or paid in cash (c)	(201,129)	$ 18.51	
Outstanding at December 31, 2011	255,975	$ 34.10	

Granted (a)	173,129	$	36.98		
Forfeited	(20,067)	$	35.34		
Vested or paid in cash (d)	(141,650)	$	30.35		
Outstanding at December 31, 2012	267,387	$	37.86	$	39.71
Expected to vest	216,399	$	37.88	$	29.09

(a) Includes the impact of conversion of the underlying securities granted under the 2010, 2011 and 2012 LTIP.
(b) The 2008 grants vested at 72%.
(c) The 2009 grants vested at 155%.
(d) The 2010 grants vested at 130%.

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The estimate of RPUs and SPUs that are expected to vest is based on highly subjective assumptions that could change over time, including the expected forfeiture rate and achievement of performance targets. Therefore the amounts of unrecognized compensation expense noted above does not necessarily represent the value that will ultimately be realized in our consolidated statements of operations.

The following table presents the fair value of units vested and the unit-based liabilities paid for unit based awards related to the strategic performance units:

	Units	Fair Value of Units Vested	Unit-Based Liabilities Paid
		(millions)	
Vested in 2010	166,237	$ 4	$ 2
Vested in 2011	201,129	$ 15	$ 3
Vested in 2012	141,650	$ 8	$ 14

Phantom Units The DERs are paid quarterly in arrears. The following table presents information related to Phantom Units:

	Units	Grant Date Weighted-Average Price Per Unit	Measurement Date Weighted-Average Price Per Unit
Outstanding at January 1, 2010	343,850	$ 25.94	
Granted	139,800	$ 30.04	
Forfeited	(7,690)	$ 27.04	
Vested	(105,670)	$ 40.15	
Outstanding at December 31, 2010	370,290	$ 23.41	
Granted	122,020	$ 38.58	
Forfeited	(1,250)	$ 32.71	
Vested	(268,090)	$ 20.78	
Outstanding at December 31, 2011	222,970	$ 34.68	
Granted (a)	175,490	$ 37.14	
Forfeited	(18,590)	$ 35.34	
Vested	(139,670)	$ 31.98	
Outstanding at December 31, 2012	240,200	$ 38.00	$ 39.74
Expected to vest	193,061	$ 38.00	$ 39.69

(a) Includes the impact of conversion of the underlying securities granted under the 2010, 2011 and 2012 LTIP.

The following table presents the fair value of units vested and the unit-based liabilities paid for unit based awards related to the phantom units:

	Units	Fair Value of Units Vested	Unit-Based Liabilities Paid
		(millions)	
Vested in 2010	105,670	$ 3	$
Vested in 2011	268,090	$ 8	$ 4
Vested in 2012	139,670	$ 6	$ 9

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DCP Partners Phantom Units The DERs are paid quarterly in arrears. The following table presents information related to the DCP Partners Phantom Units:

	Units	Grant Date Weighted-Average Price Per Unit	Measurement Date Price Per Unit
Outstanding at January 1, 2010	10,750	$ 50.43	
Granted	17,300	$ 35.56	
Vested	(10,750)	$ 31.87	
Outstanding at December 31, 2010	17,300	$ 47.09	
Vested	(5,766)	$ 35.56	
Outstanding at December 31, 2011	11,534	$ 35.56	
Vested	(5,767)	$ 35.56	
Outstanding at December 31, 2012	5,767	$ 35.56	$ 41.75
Expected to vest	5,767	$ 35.56	$ 41.75

The fair value of units that vested, and the unit-based liabilities paid during the years ended December 31, 2012, 2011 and 2010 was less than $1 million for all periods.

DCP Partners LTIP Under DCP Partners 2005 LTIP, which was adopted by DCP Midstream GP, LLC, equity instruments may be granted to key employees, consultants and directors of DCP Midstream GP, LLC and its affiliates who perform services for DCP Partners. The DCP Partners 2005 LTIP provides for the grant of limited partner units, or LPUs, phantom units, unit options and substitute awards, and, with respect to unit options and phantom units, the grant of dividend equivalent rights, or DERs. Subject to adjustment for certain events, an aggregate of 850,000 LPUs may be delivered pursuant to awards under the DCP Partners 2005 LTIP. Awards that are canceled or forfeited, or are withheld to satisfy DCP Midstream GP, LLC s tax withholding obligations, are available for delivery pursuant to other awards.

On February 15, 2012, the board of directors of DCP Midstream GP, LLC adopted a 2012 LTIP for employees, consultants and directors of DCP Midstream GP, LLC and its affiliates who perform services for DCP Partners. The 2012 LTIP provides for the grant of phantom units and the grant of DERs. The phantom units consist of a notional unit based on the value of common units or shares of DCP Partners, Spectra Energy, ConocoPhillips and Phillips 66.

The LTIPs were administered by the compensation committee of DCP Midstream GP, LLC s board of directors through 2012, and by DCP Midstream GP, LLC s board of directors beginning in 2013. All awards are subject to cliff vesting.

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DCP MIDSTREAM, LLC

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued

Years Ended December 31, 2012, 2011 and 2010

Performance Phantom Units DCP Partner s has awarded Performance Phantom Units, or PPUs, pursuant to the LTIP to certain employees. PPUs generally vest in their entirety at the end of a three year performance period. The number of PPUs that will ultimately vest range, in value up to 200% of the outstanding PPUs, depending on the achievement of specified performance targets over three year performance periods. The final performance payout is determined by the board of directors of DCP Partners general partner. The DERs are paid in cash at the end of the performance period. Of the remaining PPUs outstanding at December 31, 2012, 1,560 units are expected to vest on December 31, 2013 and 1,610 units are expected to vest on December 31, 2014. The following table presents information related to the Performance Phantom Units:

	Units	Grant Date Weighted-Average Price Per Unit	Measurement Date Price Per Unit
Outstanding at January 1, 2010	67,140	$ 15.18	
Granted	16,630	$ 31.80	
Forfeited	(2,205)	$ 15.61	
Vested	(14,215)	$ 33.44	
Outstanding at December 31, 2010	67,350	$ 15.42	
Granted	10,580	$ 41.80	
Vested	(50,720)	$ 10.05	
Outstanding at December 31, 2011	27,210	$ 35.69	
Granted (a)	11,740	$ 39.31	
Forfeited	(12,217)	$ 39.22	
Vested (b)	(22,483)	$ 34.91	
Outstanding at December 31, 2012	4,250	$ 39.63	$ 41.31
Expected to vest (c)	3,170	$ 39.76	$ 41.34

(a) Includes the impact of conversion of the underlying securities granted under the 2012 LTIP.
(b) The units vested at 121%.
(c) Based on DCP Partners December 31, 2012 estimated achievement of specified performance targets, the performance for units granted in 2012 is 100% and for units granted in 2011 is 100%. The estimated forfeiture rate for units granted in 2012 is 30% and for units granted in 2011 is 20%.

The estimate of PPUs that are expected to vest is based on highly subjective assumptions that could potentially change over time, including the expected forfeiture rate and achievement of performance targets. Therefore the amount of unrecognized compensation expense noted above does not necessarily represent the value that will ultimately be realized in our consolidated statements of operations.

The following table presents the fair value of units vested and the unit-based liabilities paid for unit based awards related to PPUs, including the related DERs:

	Year Ended December 31,		
	2012	2011	2010
		(millions)	
Fair value of units vested	$ 1	$ 5	$
Unit-based liabilities paid	$ 5	$	$ 1

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DCP MIDSTREAM, LLC

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued

Years Ended December 31, 2012, 2011 and 2010

Phantom Units In conjunction with DCP Partners initial public offering, in January 2006, the board of directors of DCP Partners general partner awarded Phantom LPUs, or Phantom Units, to key employees and to directors who are not officers or employees of affiliates of DCP Partners general partner.

As part of their director fees, DCP Partners granted 4,000 Phantom Units during each of the years ended December 31, 2012 and 2011, respectively, and 5,200 Phantom Units during the year ended December 31, 2010 to directors. All of these units vested in their respective grant years, and were settled in units.

The DERs are paid quarterly in arrears.

The following table presents information related to the Phantom Units:

	Units	Grant Date Weighted-Average Price Per Unit	Measurement Date Price Per Unit
Outstanding at January 1, 2010		$	
Granted	5,200	$ 31.80	
Vested	(5,200)	$ 31.80	
Outstanding at December 31, 2010		$	
Granted	4,000	$ 41.80	
Vested	(4,000)	$ 41.80	
Outstanding at December 31, 2011		$	
Granted	4,000	$ 48.03	
Vested	(4,000)	$ 48.03	
Outstanding at December 31, 2012		$	$

The fair value of the units that vested for the years ended December 31, 2012, 2011 and 2010 was less than $1 million for all periods.

DCP MIDSTREAM, LLC

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued

Years Ended December 31, 2012, 2011 and 2010

Restricted Phantom Units DCP Partners general partner s board of directors awarded restricted phantom LPUs, or RPUs, to key employees under the LTIP. Of the remaining RPUs outstanding at December 31, 2012, 1,560 units are expected to vest on December 31, 2013 and 1,610 units are expected to vest on December 31, 2014. The DERs are paid quarterly in arrears. The following table presents information related to the RPUs:

	Units	Grant Date Weighted-Average Price per Unit	Measurement Date Price per Unit
Outstanding at January 1, 2010	67,140	$ 15.18	
Granted	16,630	$ 31.80	
Forfeited	(2,205)	$ 15.61	
Vested	(14,215)	$ 33.44	
Outstanding at December 31, 2010	67,350	$ 15.42	
Granted	10,580	$ 41.80	
Vested	(58,600)	$ 12.97	
Outstanding at December 31, 2011	19,330	$ 37.27	
Granted (a)	11,740	$ 39.31	
Forfeited	(7,760)	$ 43.27	
Vested	(19,060)	$ 37.31	
Outstanding at December 31, 2012	4,250	$ 39.63	$ 41.31
Expected to vest	3,170	$ 39.76	$ 41.34

(a) Includes the impact of conversion of the underlying securities granted under the 2012 LTIP.

The following table presents the fair value of units vested and the unit-based liabilities paid for unit based awards related to Restricted Phantom Units:

	Year Ended December 31, 2012	2011	2010
	(millions)		
Fair value of units vested	$ 1	$ 3	$ 1
Unit-based liabilities paid	$ 2	$ 1	$

The estimate of RPUs that are expected to vest is based on highly subjective assumptions that could potentially change over time, including the expected forfeiture rate, which was estimated at 30% for units granted in 2012 and 20% for units granted in 2011. Therefore, the amount of unrecognized compensation expense noted above does not necessarily represent the value that will ultimately be realized in our consolidated statement of operations.

Duke Energy 1998 LTIP and Spectra Energy 2007 LTIP Under the Duke Energy 1998 LTIP, Duke Energy granted certain of our key employees stock options, stock-based performance awards, phantom stock awards and other stock awards to be settled in shares of Duke Energy s common stock, or the Stock-Based Awards. Upon execution of the 50-50 Transaction in July 2005, our employees incurred a change in status from Duke Energy employees to non-employees. As a result, we began accounting for these awards using the fair value method. No awards have been and we do not expect to settle any awards granted under the Duke Energy 1998 LTIP with cash. As of December 31, 2012, all units under the Duke Energy 1998 LTIP are vested.

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DCP MIDSTREAM, LLC

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued

Years Ended December 31, 2012, 2011 and 2010

In connection with the Spectra spin, one replacement Duke Energy Stock-Based Award and one-half Spectra Energy Stock-Based Award were distributed to each holder of Duke Energy Stock-Based Awards for each award held at the time of the Spectra spin. Substantially all converted Stock-Based Awards are subject to the terms and conditions applicable to the original Duke Energy Stock-Based Awards. The Spectra Energy Stock-Based Awards resulting from the conversion are considered to have been issued under the Spectra Energy 2007 LTIP, as amended and restated.

The Spectra Energy 2007 LTIP provides for the granting of stock options, restricted stock awards and units, unrestricted stock awards and units, and other equity-based awards, to employees and other key individuals who perform services for Spectra Energy. A maximum of 40 million shares of common stock may be awarded under the Spectra Energy 2007 LTIP, as amended and restated. Options granted under the Spectra Energy 2007 LTIP are issued with exercise prices equal to the fair market value of Spectra Energy common stock on the grant date, have ten year terms, and vest immediately or over terms not to exceed five years. Compensation expense related to stock options is recognized over the requisite service period. The requisite service period for stock options is the same as the vesting period, with the exception of retirement eligible employees, who have shorter requisite service periods ending when the employees become retirement eligible. Restricted, performance and phantom stock awards granted under the Spectra Energy 2007 LTIP typically become 100% vested on the three-year anniversary of the grant date. The fair value of the awards granted is measured based on the fair market value of the shares on the date of grant, and the related compensation expense is recognized over the requisite service period which is the same as the vesting period. As of December 31, 2012, all units under the Spectra Energy 2007 LTIP are vested.

Stock Options Under the Duke Energy 1998 LTIP, the exercise price of each option granted could not be less than the market price of Duke Energy s common stock on the date of grant. Effective July 1, 2005, these options were accounted using the fair value method. As a result, compensation expense subsequent to July 1, 2005, is recognized based on the change in the fair value of the stock options at each reporting date until vesting. As of December 31, 2012, all stock options granted under the Duke and Spectra plans are vested and exercisable.

On July 2, 2012, Duke Energy completed a merger with Progress Energy. Immediately preceding the merger, Duke Energy executed a one-for-three reverse stock split with respect to the issued and outstanding shares of Duke Energy common stock. The following table includes the effects of the reverse stock split on outstanding options.

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DCP MIDSTREAM, LLC

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Years Ended December 31, 2012, 2011 and 2010

The following table shows information regarding options to purchase Duke Energy s common stock granted to our employees, reflecting shares outstanding as impacted by the conversion.

	Shares	Weighted-Average Exercise Price	Weighted-Average Remaining Life (years)	Aggregate Intrinsic Value (millions)
Outstanding at January 1, 2010	1,166,792	$ 19.34		
Exercised	(56,245)	$ 8.42		
Forfeited	(401,562)	$ 24.19		
Outstanding at December 31, 2010	708,985	$ 17.46		
Exercised	(59,725)	$ 8.90		
Forfeited	(451,700)	$ 21.45		
Outstanding and Exercisable at December 31, 2011	197,560	$ 10.93		
Exercised	(62,809)	$ 10.72		
Forfeited	(42,400)	$ 21.68		
Reverse stock split	(68,368)	$ 7.91		
Outstanding and Exercisable at December 31, 2012	23,983	$ 23.62	0.2	$ 1

The total intrinsic value of options exercised during the years ended December 31, 2012, 2011 and 2010, was approximately $1 million for all periods.

The following table shows information regarding options to purchase Spectra Energy s common stock granted to our employees, reflecting shares outstanding as impacted by the conversion.

	Shares	Weighted-Average Exercise Price	Weighted-Average Remaining Life (years)	Aggregate Intrinsic Value (millions)
Outstanding at January 1, 2010	598,296	$ 28.95	2.4	
Exercised	(33,768)	$ 13.22		
Forfeited	(202,187)	$ 36.55		
Outstanding at December 31, 2010	362,341	$ 26.18		
Exercised	(29,134)	$ 12.43		
Forfeited	(227,150)	$ 32.40		

Outstanding and Exercisable at December 31, 2011	106,057	$ 16.61		
Exercised	(39,661)	$ 12.08		
Forfeited	(23,600)	$ 32.79		
Outstanding and Exercisable at December 31, 2012	42,796	$ 11.89	0.2	$ 1

The total intrinsic value of options exercised during the years ended December 31, 2012, 2011 and 2010, was less than $1 million for all periods.

Phantom Stock Awards There were no phantom stock awards granted during the years ended December 31, 2012, 2011 and 2010.

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DCP MIDSTREAM, LLC

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued

Years Ended December 31, 2012, 2011 and 2010

The following tables summarize information about phantom stock awards activity, reflecting shares outstanding as impacted by the conversion:

Duke Energy 1998 LTIP	Shares	Grant Date Weighted-Average Price Per Unit	Measurement Date Weighted-Average Price Per Unit
Outstanding at January 1, 2010	26,508	$ 15.72	
Vested	(22,516)	$ 15.59	
Outstanding at December 31, 2010	3,992	$ 16.50	
Vested	(3,992)	$ 16.50	
Outstanding at December 31, 2012 and 2011		$	$

Spectra Energy 2007 LTIP	Shares	Grant Date Weighted-Average Price Per Unit	Measurement Date Weighted-Average Price Per Unit
Outstanding at January 1, 2010	13,254	$ 23.76	
Vested	(11,258)	$ 23.55	
Outstanding at December 31, 2010	1,996	$ 24.94	
Vested	(1,996)	$ 24.94	
Outstanding at December 31, 2012 and 2011		$	$

There were no phantom stock awards which vested during the year ended December 31, 2012. The total fair value of the phantom stock awards that vested during the years ended December 31, 2011 and 2010 was less than $1 million for both periods.

13. Benefits

All Company employees who have reached the age of 18 and work at least 20 hours per week are eligible for participation in our 401(k) and retirement plan, to which we contribute a range of 4% to 7% of each eligible employee s qualified earnings to the retirement plan, based on years of service. Additionally, we match employees contributions in the 401(k) plan up to 6% of qualified earnings. During the years ended December 31, 2012, 2011 and 2010 we expensed plan contributions of $27 million, $25 million and $21 million, respectively. In conjunction with the Marysville Hydrocarbons Holdings, LLC, or Marysville, acquisition on December 30, 2010, DCP Partners acquired two 401(k) plans. One of these plans was incorporated into the DCP Midstream 401(k) plan during 2011.

We offer certain eligible executives the opportunity to participate in DCP Midstream LP s Non-Qualified Executive Deferred Compensation Plan. This plan allows participants to defer current compensation on a pre-tax basis and to receive tax deferred earnings on such contributions.

The plan also has make-whole provisions for plan participants who may otherwise be limited in the amount that we can contribute to the 401(k) plan on the participant s behalf. All amounts contributed to or earned by the plan s investments are held in a trust account for the benefit of the participants. The trust and the liability to the participants are part of our general assets and liabilities, respectively.

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DCP MIDSTREAM, LLC

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Years Ended December 31, 2012, 2011 and 2010

14. Income Taxes

We are structured as a limited liability company, which is a pass-through entity for federal income tax purposes. We own a corporation that files its own federal, foreign and state corporate income tax returns. The income tax expense related to this corporation is included in our income tax expense, along with state and local taxes of the limited liability company and other subsidiaries.

On December 30, 2010, DCP Partners acquired all of the interests in Marysville, an entity that owned a taxable C-Corporation consolidated return group. We estimated $35 million of deferred tax liabilities resulting from built-in tax gains recognized in the transaction and recorded this in our preliminary purchase price allocation as of December 31, 2010. On January 4, 2011, DCP Partners merged two wholly-owned subsidiaries of Marysville and converted the combined entity s organizational structure from a corporation to a limited liability company. This conversion to a limited liability company triggered the deferred tax liabilities resulting from built-in tax gains to become currently payable. Accordingly, the estimated $35 million of deferred tax liabilities at December 31, 2010 became currently payable on January 4, 2011. During 2011, DCP Partners made estimated federal and state tax payments totaling $29 million and less than $1 million, respectively, related to their estimated $35 million tax liability that resulted from the acquisition of Marysville. The remaining $6 million estimated tax liability was reclassified to goodwill in DCP Partners final accounting for the Marysville business combination.

The State of Texas imposes a margin tax that is assessed at 1% of taxable margin apportioned to Texas. Accordingly, we have recorded current tax expense for the Texas margin tax. For the years ended December 31, 2011 and 2010, the state of Michigan imposed a business tax of 0.8% on gross receipts and 4.95% of Michigan taxable income. The sum of gross receipts and income tax is subject to a tax surcharge of 21.99%. The Michigan business tax was repealed for the year ended December 31, 2012.

Income tax expense consisted of the following:

	Year Ended December 31,		
	2012	2011 (millions)	2010
Current:			
Federal income tax expense	$	$ (29)	$
State income tax expense	(3)	(10)	(9)
Deferred:			
Federal income tax benefit	3	34	5
State income tax (expense) benefit	(2)	2	(1)
Total income tax expense	$ (2)	$ (3)	$ (5)

We had net long-term deferred tax liabilities of $92 million and $93 million as of December 31, 2012 and 2011, respectively. The net long-term deferred tax liabilities are included in deferred income taxes on the consolidated balance sheets. The deferred tax liabilities of $135 million and $126 million as of December 31, 2012 and 2011, respectively, are primarily associated with depreciation and amortization related to the acquired intangible assets and property, plant and equipment. Offsetting the deferred tax liabilities are deferred tax assets related to the net operating loss of an affiliate corporation of approximately $43 million and $33 million as of December 31, 2012 and 2011, respectively. The net operating losses begin expiring in 2027. We expect to fully utilize the net operating loss carryovers, and, accordingly we have not provided a valuation allowance for the net deferred tax asset.

DCP MIDSTREAM, LLC

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued

Years Ended December 31, 2012, 2011 and 2010

Our effective tax rate differs from statutory rates primarily due to our being structured as a limited liability company, which is a pass-through entity for federal income tax purposes, while being treated as a taxable entity in certain states. Additionally, some of our subsidiaries are tax paying entities for federal income tax purposes.

15. Commitments and Contingent Liabilities

Litigation The midstream industry has seen a number of class action lawsuits involving royalty disputes, mismeasurement and mispayment allegations. We are currently named as defendants in some of these cases and customers have asserted individual audit claims related to mismeasurement and mispayment. Management believes we have meritorious defenses to these cases and, therefore, will continue to defend them vigorously. These claims, however, can be costly and time consuming to defend. We are also a party to various legal, administrative and regulatory proceedings that have arisen in the ordinary course of our business, including, from time to time, disputes with customers over various measurement and settlement issues.

Management currently believes that these matters, taken as a whole, and after consideration of amounts accrued, insurance coverage and other indemnification arrangements, will not have a material adverse effect upon our consolidated results of operations, financial position or cash flows.

General Insurance Our insurance coverage is carried with an affiliate of Phillips 66, an affiliate of Spectra Energy and third-party insurers. Our insurance coverage includes: (1) general liability insurance covering third-party exposures; (2) statutory workers compensation insurance; (3) automobile liability insurance for all owned, non-owned and hired vehicles; (4) excess liability insurance above the established primary limits for general liability and automobile liability insurance; (5) property insurance, which covers the replacement value of real and personal property and includes business interruption; and (6) directors and officers insurance covering our directors and officers for acts related to our business activities. All coverage is subject to certain limits and deductibles, the terms and conditions of which are common for companies with similar types of operations.

Environmental The operation of pipelines, plants and other facilities for gathering, processing, compressing, transporting, or storing natural gas, and fractionating, transporting, gathering, processing and storing NGLs and other products is subject to stringent and complex laws and regulations pertaining to health, safety and the environment. As an owner or operator of these facilities, we must comply with United States laws and regulations at the federal, state and local levels that relate to air and water quality, hazardous and solid waste storage, management, transportation and disposal, and other environmental matters including recently adopted U.S. Environmental Protection Agency regulations related to reporting of greenhouse gas emissions which have taken effect over the past two years. The cost of planning, designing, constructing and operating pipelines, plants, and other facilities must incorporate compliance with environmental laws and regulations and safety standards. In addition, there is increasing focus, both from state and federal regulatory officials and through litigation, on hydraulic fracturing and the real or perceived environmental impacts of this technique, which indirectly presents some risk to our available supply of natural gas. Failure to comply with these laws and regulations may trigger a variety of administrative, civil and potentially criminal enforcement measures, including citizen suits, which can include the assessment of monetary penalties, the imposition of remedial requirements, the issuance of injunctions or restrictions on operations. Management believes that, based on currently known information, compliance with these laws and regulations will not have a material adverse effect on our consolidated results of operations, financial position or cash flows.

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DCP MIDSTREAM, LLC

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued

Years Ended December 31, 2012, 2011 and 2010

We make expenditures in connection with environmental matters as part of our normal operations. As of December 31, 2012 and 2011, environmental liabilities included in the consolidated balance sheets as other current liabilities amounted to $5 million and $6 million, respectively, and environmental liabilities included in the consolidated balance sheets as other long-term liabilities amounted to $9 million and $9 million, respectively.

Operating Leases We utilize assets under operating leases in several areas of operations. Consolidated rental expense, including leases with no continuing commitment, amounted to $36 million, $38 million and $38 million in 2012, 2011 and 2010, respectively. Rental expense for leases with escalation clauses is recognized on a straight line basis over the initial lease term.

Minimum rental payments under our various operating leases in the year indicated are as follows:

	Minimum Rental Payments (millions)
2013	$ 49
2014	39
2015	30
2016	21
2017	16
Thereafter	61
Total minimum lease payments	$ 216

16. Guarantees and Indemnifications

We periodically enter into agreements for the acquisition, contribution or divestiture of assets. These agreements contain indemnification provisions that may provide indemnity for environmental, tax, employment, outstanding litigation, breaches of representations, warranties and covenants, performance of DCP Partners or other liabilities related to the assets being acquired, contributed or divested. Claims may be made by third parties or DCP Partners under these indemnification agreements for various periods of time depending on the nature of the claim. The effective periods on these indemnification provisions generally have terms of one to 15 years, although some are longer. Our maximum potential exposure under these indemnification agreements can vary depending on the nature of the claim and the particular transaction. We are unable to estimate the total maximum potential amount of future payments under indemnification agreements due to several factors, including uncertainty as to whether claims will be made under these indemnities. We have issued guarantees and indemnifications for certain of our consolidated subsidiaries.

17. Supplemental Cash Flow Information

	Year Ended December 31,		
	2012	2011	2010
		(millions)	
Cash paid for interest, net of capitalized interest	$ 169	$ 196	$ 256
Cash paid for income taxes, net of refunds	$ 6	$ 37	$ 6
Non-cash investing and financing activities:			
Distributions payable to members	$	$ 95	$ 77

Property, plant and equipment acquired with accounts payable	$ 158	$ 118	$ 72
Other non-cash additions of property, plant and equipment	$ 59	$ 9	$ 7
Acquisition related contingent consideration	$	$	$ 4

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DCP MIDSTREAM, LLC

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued

Years Ended December 31, 2012, 2011 and 2010

During the years ended December 31, 2012, 2011 and 2010, we received distributions from DCP Partners of $75 million, $53 million and $45 million, respectively, which are eliminated in consolidation.

18. Valuation and Qualifying Accounts and Reserves

Our valuation and qualifying accounts and reserves for the years ended December 31, 2012, 2011 and 2010 are as follows:

	Balance at Beginning of Period	Charged to Consolidated Statements of Operations	Charged to Other Accounts (b)	Deductions (c)	Balance at End of Period
			(millions)		
December 31, 2012:					
Allowance for doubtful accounts	$ 2	$	$	$	$ 2
Environmental	15	2		(3)	14
Litigation	3			(2)	1
Other (a)	1			(1)	
	$ 21	$ 2	$	$ (6)	$ 17
December 31, 2011:					
Allowance for doubtful accounts	$ 2	$	$	$	$ 2
Environmental	15	3		(3)	15
Litigation	2	2		(1)	3
Other (a)	3	1		(3)	1
	$ 22	$ 6	$	$ (7)	$ 21
December 31, 2010:					
Allowance for doubtful accounts	$ 3	$	$	$ (1)	$ 2
Environmental	16	3		(4)	15
Litigation	6			(4)	2
Other (a)	1		4	(2)	3
	$ 26	$ 3	$ 4	$ (11)	$ 22

(a) Principally consists of other contingency reserves, which are included in other current liabilities.

(b) Consists of the fair value of contingent consideration recognized in relation to acquisitions and the purchase of an additional interest in a subsidiary.

(c) Consists of cash payments, collections, reserve reversals, liabilities settled, and the re-measurement of the fair value of contingent consideration.

19. Subsequent Events

We have evaluated subsequent events occurring through February 22, 2013, the date the consolidated financial statements were issued.

On January 28, 2013, DCP Partners announced that the board of directors of DCP Partners general partner declared a quarterly distribution of $0.69 per unit, payable on February 14, 2013 to unitholders of record on February 7, 2013.

In January 2013, our board of directors approved a $104 million dividend which was paid in January 2013.

EXHIBIT INDEX

Exhibit No.	Exhibit Description
2.1	Separation and Distribution Agreement by and between Duke Energy Corporation and Spectra Energy Corp, dated as of December 13, 2006 (filed as Exhibit No. 2.1 to Form 8-K of Spectra Energy Corp on December 15, 2006).
2.2	Reorganization Agreement by and among ConocoPhillips, Duke Capital LLC and DCP Midstream, LLC, dated as of May 26, 2005 (filed as Exhibit No. 10.4 to Form 10-Q of Duke Energy Corporation for the quarter ended June 30, 2005, File No. 1-4928).
2.2.1	First Amendment to Reorganization Agreement by and among ConocoPhillips, Duke Capital LLC and DCP Midstream, LLC, dated as of June 30, 2005 (filed as Exhibit No. 10.4.1 to Form 10-Q of Duke Energy Corporation for the quarter ended June 30, 2005).
2.2.2	Second Amendment to Reorganization Agreement by and among ConocoPhillips, Duke Capital LLC and DCP Midstream, LLC, dated as of July 11, 2005 (filed as Exhibit No. 10.4.2 to Form 10-Q of Duke Energy Corporation for the quarter ended June 30, 2005).
2.3	Amended and Restated Combination Agreement, dated as of September 20, 2001, among Duke Energy Corporation, 3058368 Nova Scotia Company, 3946509 Canada Inc. and Westcoast Energy Inc. (filed as Exhibit No. 10.7 to Form 10-Q of Duke Energy Corporation for the quarter ended September 30, 2001).
2.4	Spectra Energy Support Agreement dated as of January 1, 2007, between Spectra Energy Corp, Duke Energy Canada Call Co. and Duke Energy Canada Exchangeco Inc. (filed as Exhibit No. 2.2 to Form S-3 of Spectra Energy Corp on January 17, 2007).
2.5	Spectra Energy Voting and Exchange Trust Agreement dated as of January 1, 2007, between Spectra Energy Corp, Duke Energy Canada Exchangeco Inc. and Computershare Trust Company, Inc. (filed as Exhibit No. 2.3 to Form S-3 of Spectra Energy Corp on January 17, 2007).
2.6	Plan of Arrangement, as approved by the Supreme Court of British Columbia by final order dated December 15, 2006 (filed as Exhibit No. 2.4 to Form S-3 of Spectra Energy Corp on January 17, 2007).
2.7	Securities Purchase Agreement by and among BPC Penco Corporation, Kinder Morgan Energy Partners, L.P., Ontario Teachers Pension Plan Board, Blackhawk Holdings Trust, 2349466 (U.S.) Grantor Trust, Express US Holdings LP, Express Holdings (Canada) Limited Partnership and 6048935 Canada Inc, dated as of December 10, 2012 (filed as Exhibit No. 2.1 to Form 8-K of Spectra Energy Corp on December 11, 2012).
3.1	Amended and Restated Certificate of Incorporation of Spectra Energy Corp (filed as Exhibit No. 3.1 to Form 8-K of Spectra Energy Corp on December 15, 2006).
3.1.1	Certificate of Amendment to the Amended and Restated Certificate of Incorporation of Spectra Energy Corp (filed as Exhibit No. 3.1 to Form 8-K of Spectra Energy Corp on May 7, 2012).
3.2	Second Amended and Restated By-Laws of Spectra Energy Corp (filed as Exhibit No. 3.2 to Form 8-K of Spectra Energy Corp on May 7, 2012).
4.1	Senior Indenture between Duke Capital Corporation and The Chase Manhattan Bank, dated as of April 1, 1998 (filed as Exhibit No. 4.1 to Form S-3 of Duke Capital Corporation on April 1, 1998, File No. 333-71297).
4.2	First Supplemental Indenture, dated July 20, 1998, between Duke Capital Corporation and The Chase Manhattan Bank (filed as Exhibit No. 4.2 to Form 10-K of Duke Capital Corporation on March 16, 2004).
4.3	Second Supplemental Indenture, dated September 28, 1999, between Duke Capital Corporation and The Chase Manhattan Bank (filed as Exhibit No. 4.3 to Form 10-K of Duke Capital Corporation on March 16, 2004).

Exhibit No.	Exhibit Description
4.4	Fifth Supplemental Indenture, dated February 15, 2002, between Duke Capital Corporation and JPMorgan Chase Bank (filed as Exhibit No. 4.6 to Form 10-K of Duke Capital Corporation on March 16, 2004).
4.5	Ninth Supplemental Indenture, dated February 20, 2004, between Duke Capital Corporation and JPMorgan Chase Bank (filed as Exhibit No. 4.10 to Form 10-K of Duke Capital Corporation on March 16, 2004).
4.6	Eleventh Supplemental Indenture, dated August 19, 2004, between Duke Capital LLC and JPMorgan Chase Bank (filed as Exhibit No. 4.6 to Form S-3 of Spectra Energy Corp and Spectra Energy Capital, LLC on March 26, 2008, File No. 333-141982).
4.7	Twelfth Supplemental Indenture, dated December 14, 2007, among Spectra Energy Capital, LLC, Spectra Energy Corp and The Bank of New York (filed as Exhibit No. 10.1 to Form 8-K of Spectra Energy Corp on December 20, 2007).
4.8	Thirteenth Supplemental Indenture, dated as of April 10, 2008, between Spectra Energy Capital, LLC, Spectra Energy Corp and The Bank of New York Trust Company, N.A. (filed as Exhibit No. 4.1 to Form 8-K on April 10, 2008).
4.9	Fourteenth Supplemental Indenture, dated as of September 8, 2008, between Spectra Energy Capital, LLC, Spectra Energy Corp and The Bank of New York Mellon Trust Company, N.A. (filed as Exhibit No. 4.1 to Form 8-K on September 9, 2008).
4.10	Indenture, dated May 14, 2009, between Maritimes & Northeast Pipeline, LLC and Deutsche Bank Trust Company Americas (filed as Exhibit No. 4.1 to Form 10-Q of Spectra Energy Corp for the quarter ended June 30, 2009).
4.11	First Supplemental Indenture, dated May 14, 2009, between Maritimes & Northeast Pipeline, LLC and Deutsche Bank Trust Company Americas (filed as Exhibit No. 4.2 to Form 10-Q of Spectra Energy Corp for the quarter ended June 30, 2009).
4.12	Fifteenth Supplemental Indenture, dated as of August 28, 2009, between Spectra Energy Capital, LLC, Spectra Energy Corp and The Bank of New York Mellon Trust Company, N.A. (filed as Exhibit No. 4.1 to Form 8-K on August 28, 2009).
10.1	Tax Matters Agreement by and among Duke Energy Corporation, Spectra Energy Corp, and The Other Spectra Energy Parties, dated as of December 13, 2006 (filed as Exhibit No. 10.1 to Form 10-Q of Spectra Energy Corp for the quarter ended June 30, 2009).
10.2	Employee Matters Agreement by and between Duke Energy Corporation and Spectra Energy Corp, dated as of December 13, 2006 (filed as Exhibit No. 10.3 to Form 10-Q of Spectra Energy Corp for the quarter ended June 30, 2009).
10.2.1	First Amendment to Employee Matters Agreement, dated as of September 28, 2007, by and between Duke Energy Corporation and Spectra Energy Corp (filed as Exhibit No. 10.3.1 to Form 10-Q of Spectra Energy Corp for the quarter ended June 30, 2009).
10.3	Purchase and Sale Agreement, dated as of February 24, 2005, by and between Enterprise GP Holdings LP and DCP Midstream, LLC (filed as Exhibit No. 10.4 to Form 10-Q of Spectra Energy Corp for the quarter ended June 30, 2009).
10.4	Term Sheet Regarding the Restructuring of DCP Midstream, LLC, dated as of February 23, 2005, between Duke Energy Corporation and ConocoPhillips (filed as Exhibit No. 10.26 to Form 10-K of Duke Energy Corporation for the year ended December 31, 2004).
10.5	Second Amended and Restated Limited Liability Company Agreement of DCP Midstream, LLC by and between ConocoPhillips Gas Company and Duke Energy Enterprises Corporation, dated as of July 5, 2005 (filed as Exhibit No. 10.5 to Form 10-Q of Spectra Energy Corp for the quarter ended June 30, 2009).

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Exhibit No.	Exhibit Description
10.5.1	First Amendment, dated August 11, 2006, to Second Amended and Restated Limited Liability Company Agreement of DCP Midstream, LLC, by and between ConocoPhillips Gas Company and Duke Energy Enterprises Corporation (filed as Exhibit No. 10.5.1 to Form 10-K of Spectra Energy Corp for the year ended December 31, 2011).
10.5.2	Second Amendment, dated February 1, 2007, to Second Amended and Restated Limited Liability Company Agreement of DCP Midstream, LLC, by and between ConocoPhillips Gas Company and Spectra Energy DEFS Holding, LLC and Spectra Energy DEFS Holding Corp (filed as Exhibit No. 10.5.2 to Form 10-K of Spectra Energy Corp for the year ended December 31, 2011).
10.5.3	Third Amendment, dated April 30, 2009, to Second Amended and Restated Limited Liability Company Agreement of DCP Midstream, LLC, by and between ConocoPhillips Gas Company and Spectra Energy DEFS Holding, LLC and Spectra Energy DEFS Holding Corp (filed as Exhibit No. 10.5.3 to Form 10-K of Spectra Energy Corp for the year ended December 31, 2011).
10.5.4	Fourth Amendment, dated November 9, 2010, to Second Amended and Restated Limited Liability Company Agreement of DCP Midstream, LLC, by and between ConocoPhillips Gas Company and Spectra Energy DEFS Holding, LLC and Spectra Energy DEFS Holding Corp (filed as Exhibit No. 10.5.4 to Form 10-K of Spectra Energy Corp for the year ended December 31, 2011).
10.6	Limited Liability Company Agreement of Gulfstream Management & Operating Services, LLC, dated as of February 1, 2001, between Duke Energy Gas Transmission Corporation and Williams Gas Pipeline Company (filed as Exhibit No. 10.18 to Form 10-K of Duke Energy Corporation for the year ended December 31, 2002).
10.7	Loan Agreement, dated as of February 25, 2005, between DCP Midstream, LLC and Duke Capital LLC (filed as Exhibit No. 10.6 to Form 10-Q of Spectra Energy Corp for the quarter ended June 30, 2009).
+10.8	Spectra Energy Corp Directors Savings Plan, as amended and restated (filed as Exhibit No. 10.2 to Form 10-Q of Spectra Energy Corp for the quarter ended June 30, 2012).
+10.9	Spectra Energy Corp Executive Savings Plan, as amended and restated (filed as Exhibit No. 10.1 to Form 10-Q of Spectra Energy Corp for the quarter ended June 30, 2012).
+10.10	Spectra Energy Corp Executive Cash Balance Plan, as amended and restated (filed as Exhibit No. 10.3 to Form 10-K of Spectra Energy Corp for the year ended December 31, 2011).
+10.11	Form of Change in Control Agreement (U.S.) (filed as Exhibit No. 10.11 to Form 10-K of Spectra Energy Corp for the year ended December 31, 2011).
+10.12	Form of Change in Control Agreement (Canada) (filed as Exhibit No. 10.12 to Form 10-K of Spectra Energy Corp for the year ended December 31, 2011).
+10.13	Form of Non-Qualified Stock Option Agreement pursuant to the Spectra Energy Corp 2007 Long-Term Incentive Plan (filed as Exhibit No. 10.18 to Form 10-K of Spectra Energy Corp for the year ended December 31, 2006).
10.14	Support Agreement among Spectra Energy Midstream Holdco Management Partnership, Spectra Energy Income Fund and Spectra Energy Commercial Trust, dated March 4, 2008 (filed as Exhibit No. 10.1 to Form 10-Q of Spectra Energy Corp for the quarter ended March 31, 2008).
+10.15	Form of Phantom Stock Award Agreement (2010) pursuant to the Spectra Energy Corp 2007 Long-Term Incentive Plan (filed as Exhibit No. 10.19 to Form 10-K of Spectra Energy Corp for the year ended December 31, 2009).
+10.16	Form of Performance Award Agreement (2010) pursuant to the Spectra Energy Corp 2007 Long-Term Incentive Plan (filed as Exhibit No. 10.20 to Form 10-K of Spectra Energy Corp for the year ended December 31, 2009).

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Exhibit No.	Exhibit Description
+10.17	Form of Retention Stock Award Agreement (2010) pursuant to the Spectra Energy Corp 2007 Long-Term Incentive Plan (filed as Exhibit No. 10.1 to Form 10-Q of Spectra Energy Corp for the quarter ended June 30, 2010).
+10.18	Spectra Energy Corp 2007 Long-Term Incentive Plan, as amended and restated (filed as Exhibit No. 10.1 to Form 8-K of Spectra Energy Corp on April 22, 2011).
+10.19	Spectra Energy Corp Executive Short-Term Incentive Plan, as amended and restated (filed as Exhibit No. 10.2 to Form 8-K of Spectra Energy Corp on April 22, 2011).
+10.20	Form of Phantom Stock Award Agreement (2011) pursuant to the Spectra Energy Corp 2007 Long-Term Incentive Plan (filed as Exhibit No. 10.3 to Form 10-Q of Spectra Energy Corp on May 5, 2011).
+10.21	Form of Performance Award Agreement (cash) (2011) pursuant to the Spectra Energy Corp 2007 Long-Term Incentive Plan (filed as Exhibit No. 10.4 to Form 10-Q of Spectra Energy Corp on May 5, 2011).
+10.22	Form of Performance Award Agreement (stock) (2011) pursuant to the Spectra Energy Corp 2007 Long-Term Incentive Plan (filed as Exhibit No. 10.5 to Form 10-Q of Spectra Energy Corp on May 5, 2011).
10.23	Acknowledgement and Waiver Agreement, dated as of September 6, 2011, by and among ConocoPhillips, ConocoPhillips Gas Company, Spectra Energy Corp, Spectra Energy DEFS Holding, LLC and Spectra Energy DEFS Holding Corp (filed as Exhibit No. 10.1 to Form 8-K of Spectra Energy Corp on September 12, 2011).
10.24	Credit Agreement, dated as of October 18, 2011, among Spectra Energy Capital, LLC, as Borrower, Spectra Energy Corp, as Parent, the Initial Lenders named therein and JPMorgan Chase Bank, N.A., as Administrative Agent (filed as Exhibit No. 10.1 to Form 8-K of Spectra Energy Corp on October 20, 2011).
+10.25	Form of Phantom Stock Award Agreement (2012) pursuant to the Spectra Energy Corp 2007 Long-Term Incentive Plan (filed as Exhibit No. 10.1 to Form 10-Q of Spectra Energy Corp on May 9, 2011).
+10.26	Form of Performance Award Agreement (cash) (2012) pursuant to the Spectra Energy Corp 2007 Long-Term Incentive Plan (filed as Exhibit No. 10.2 to Form 10-Q of Spectra Energy Corp on May 9, 2011).
+10.27	Form of Performance Award Agreement (stock) (2012) pursuant to the Spectra Energy Corp 2007 Long-Term Incentive Plan (filed as Exhibit No. 10.3 to Form 10-Q of Spectra Energy Corp on May 9, 2011).
*12.1	Computation of Ratio of Earnings to Fixed Charges.
*21.1	Subsidiaries of the Registrant.
*23.1	Consent of Independent Registered Public Accounting Firm.
*23.2	Consent of Independent Auditors.
*24.1	Power of Attorney.
*31.1	Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*31.2	Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*32.1	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*32.2	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

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Exhibit No.	Exhibit Description
*101.INS	XBRL Instance Document.
*101.SCH	XBRL Taxonomy Extension Schema.
*101.CAL	XBRL Taxonomy Extension Calculation Linkbase.
*101.DEF	XBRL Taxonomy Extension Definition Linkbase.
*101.LAB	XBRL Taxonomy Extension Label Linkbase.
*101.PRE	XBRL Taxonomy Extension Presentation Linkbase.

+ Denotes management contract or compensatory plan or arrangement.

* Filed herewith.

The total amount of securities of the registrant or its subsidiaries authorized under any instrument with respect to long-term debt not filed as an exhibit does not exceed 10% of the total assets of the registrant and its subsidiaries on a consolidated basis. The registrant agrees, upon request of the Securities and Exchange Commission, to furnish copies of any or all of such instruments to it.