

Edgar Filing: Spectra Energy Corp. - Form 10-K

Spectra Energy Corp.
Form 10-K
February 25, 2016

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 10-K

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

For the fiscal year ended December 31, 2015 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 ☒ No ☐

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

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

Indicate by check mark 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 ☒ 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 ☒ 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 ☒

Estimated aggregate market value of the common equity held by nonaffiliates of the registrant June 30, 2015:

\$22,000,000,000

Number of shares of Common Stock, \$0.001 par value, outstanding at January 31, 2016: 671,500,270

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the proxy statement for the 2016 Annual Meeting of Shareholders are incorporated by reference in Part III.

SPECTRA ENERGY CORP
FORM 10-K FOR THE YEAR ENDED
DECEMBER 31, 2015
TABLE OF CONTENTS

Item	Page
PART I.	
1. <u>Business</u>	4
<u>General</u>	4
<u>Businesses</u>	5
<u>Spectra Energy Partners</u>	5
<u>Distribution</u>	17
<u>Western Canada Transmission & Processing</u>	19
<u>Field Services</u>	21
<u>Supplies and Raw Materials</u>	23
<u>Regulations</u>	23
<u>Environmental Matters</u>	24
<u>Geographic Regions</u>	25
<u>Employees</u>	25
<u>Executive and Other Officers</u>	26
<u>Additional Information</u>	27
1A. <u>Risk Factors</u>	27
1B. <u>Unresolved Staff Comments</u>	32
2. <u>Properties</u>	32
3. <u>Legal Proceedings</u>	32
4. <u>Mine Safety Disclosures</u>	32
PART II.	
5. <u>Market for Registrant’s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities</u>	33
6. <u>Selected Financial Data</u>	34
7. <u>Management’s Discussion and Analysis of Financial Condition and Results of Operations</u>	35
7A. <u>Quantitative and Qualitative Disclosures About Market Risk</u>	63
8. <u>Financial Statements and Supplementary Data</u>	63
9. <u>Changes in and Disagreements with Accountants on Accounting and Financial Disclosure</u>	122
9A. <u>Controls and Procedures</u>	122
9B. <u>Other Information</u>	123
PART III.	
10. <u>Directors, Executive Officers and Corporate Governance</u>	123
11. <u>Executive Compensation</u>	123
12. <u>Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters</u>	123
13. <u>Certain Relationships and Related Transactions, and Director Independence</u>	123
14. <u>Principal Accounting Fees and Services</u>	123
PART IV.	
15. <u>Exhibits, Financial Statement Schedules</u>	124
<u>Signatures</u>	125
<u>Exhibit Index</u>	

Table of Contents

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, provincial, 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 and costs 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 United States 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 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.

Table of Contents

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. The term “Spectra Energy Partners” refers to our Spectra Energy Partners operating segment. The term “SEP” refers to Spectra Energy Partners, LP, our master limited partnership.

General

Spectra Energy, 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. We also own and operate a crude oil pipeline system that connects Canadian and United States (U.S.) producers to refineries in the U.S. Rocky Mountain and Midwest regions. 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 transmission and storage of natural gas to customers in various regions of the northeastern and southeastern U.S., the Maritime provinces in Canada, the Pacific Northwest in the U.S. and Canada, and in the province of Ontario, Canada. We also provide natural gas sales and distribution services to retail customers in Ontario, and natural gas gathering and processing services to customers in western Canada. We also own a 50% interest in DCP Midstream, LLC (DCP Midstream), based in Denver, Colorado, one of the leading natural gas gatherers in the U.S., and one of the largest U.S. producers and marketers of natural gas liquids (NGLs). Our internet website is <http://www.spectraenergy.com>.

Our natural gas pipeline systems consist of approximately 21,000 miles of transmission pipelines. Our storage facilities provide approximately 300 billion cubic feet (Bcf) of net storage capacity in the U.S. and Canada. Our crude oil pipeline system, Express-Platte, consists of over 1,700 miles of transmission pipeline comprised of the Express pipeline and the Platte pipeline systems.

Table of Contents

Businesses

We manage our business in four reportable segments: Spectra Energy Partners, Distribution, Western Canada Transmission & Processing and Field Services. The remainder of our business operations is presented as “Other,” and consists of unallocated corporate costs, employee benefit plan assets and liabilities, 100%-owned captive insurance subsidiaries, 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.

SPECTRA ENERGY PARTNERS

We currently own a 78% equity interest in SEP, a natural gas, crude oil and NGL infrastructure master limited partnership, which owns 100% of Texas Eastern Transmission, LP (Texas Eastern), 100% of Algonquin Gas Transmission, LLC (Algonquin), 100% of East Tennessee Natural Gas, LLC (East Tennessee), 100% of Express-Platte, 100% of Saltville Gas Storage Company L.L.C. (Saltville), 100% of Ozark Gas Gathering, L.L.C. (Ozark Gas Gathering) and Ozark Gas Transmission, L.L.C. (Ozark Gas Transmission), 100% of Big Sandy Pipeline, LLC (Big Sandy), 100% of Market Hub Partners Holding (Market Hub), 100% of Bobcat Gas Storage (Bobcat), 78% of Maritimes & Northeast Pipeline, L.L.C. (M&N U.S.), 50% of Southeast Supply Header, LLC (SESH), 50% of Steckman Ridge, LP (Steckman Ridge) and 50% of Gulfstream Natural Gas System, L.L.C. (Gulfstream).

On October 30, 2015, Spectra Energy acquired SEP's 33.3% ownership interests in DCP Sand Hills Pipeline, LLC (Sand Hills) and DCP Southern Hills Pipeline, LLC (Southern Hills). See Part II. Item 8. Financial Statements and Supplementary Data, Notes 2 and 3 of Notes to Consolidated Financial Statements for further discussion.

SEP is a publicly traded entity which trades on the New York Stock Exchange (NYSE) 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 SEP.

Our Spectra Energy Partners business primarily provides transmission, storage and gathering of natural gas, as well as the transportation and storage of crude oil through interstate pipeline systems for customers in various regions of the midwestern, northeastern and southern U.S. and Canada. Its pipeline systems consist of approximately 15,400 miles of transmission and transportation pipelines. The pipeline systems in our Spectra Energy Partners business receive natural gas and crude oil 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. Demand on the natural gas pipeline and storage systems is seasonal, with the highest throughput occurring during colder periods in the first and fourth quarters, and storage injections occurring primarily during the summer periods.

Most of Spectra Energy Partners' 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 and crude oil in interstate commerce. The National Energy Board (NEB) is the Canadian agency that regulates the transportation of crude oil in Canada.

Table of Contents

Texas Eastern

We have an effective 78% ownership interest in Texas Eastern through our ownership of SEP. 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, the first of which has one to four 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 400 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 joint venture capacity in these three facilities is 74 Bcf. In addition, Texas Eastern's system is connected to Steckman Ridge, a 12 Bcf joint venture storage facility in Pennsylvania, and three affiliated storage facilities in Texas and Louisiana, aggregating 77 Bcf, owned by Market Hub and Bobcat.

Table of Contents

Algonquin

We have an effective 78% ownership interest in Algonquin through our ownership of SEP. 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 the Maritimes & Northeast Pipeline. The system consists of approximately 1,130 miles of pipeline with associated compressor stations.

7

Table of Contents

East Tennessee

We have an effective 78% ownership interest in East Tennessee through our ownership of SEP. 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.

Table of Contents

Maritimes & Northeast Pipeline

We have an effective 60% ownership interest in M&N U.S. through our ownership of SEP. M&N U.S. is owned 78% directly by SEP, with affiliates of Emera, Inc. and Exxon Mobil Corporation directly owning the remaining 13% and 9% interests, respectively. M&N U.S. is an approximately 350-mile mainline interstate natural gas transmission system which extends from the border of Canada near Baileyville, Maine to northeastern Massachusetts. M&N U.S. is connected to the Canadian portion of the Maritimes & Northeast Pipeline system, Maritimes & Northeast Pipeline Limited Partnership (M&N Canada), which is owned 78% by us as part of our Western Canada Transmission & Processing segment. M&N U.S. facilities include compressor stations, with a market delivery capability of approximately 0.8 billion cubic feet per day (Bcf/d) of natural gas. The pipeline's location and key interconnects with our transmission system link regional natural gas supplies to the northeast U.S. markets.

Table of Contents

Ozark

We have an effective 78% ownership interest in Ozark Gas Transmission and Ozark Gas Gathering through our ownership of SEP. Ozark Gas Transmission consists of an approximately 365-mile natural gas transmission system extending from southeastern Oklahoma through Arkansas to southeastern Missouri. Ozark Gas Gathering consists of an approximately 330-mile natural gas gathering system, with associated compressor stations, that primarily serves Arkoma basin producers in eastern Oklahoma.

10

Table of Contents

Big Sandy

We have an effective 78% ownership interest in Big Sandy through our ownership of SEP. Big Sandy is an approximately 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.

11

Table of Contents

Gulfstream

We have an effective 39% investment in Gulfstream through our ownership of SEP. Gulfstream is an approximately 745-mile interstate natural gas transmission system, with associated compressor stations, operated jointly by us and The Williams Companies, Inc. (Williams). Gulfstream transports natural gas from Mississippi, Alabama, Louisiana and Texas, crossing the Gulf of Mexico to markets in central and southern Florida. Gulfstream is owned 50% directly by SEP and 50% by affiliates of Williams. Our investment in Gulfstream is accounted for under the equity method of accounting.

12

Table of Contents

Express-Platte

We have an effective 78% ownership interest in Express-Platte, acquired in 2013, through our ownership of SEP. The Express-Platte pipeline system, an approximately 1,700-mile crude oil transportation 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, including Montana, Wyoming, Colorado and Utah. The Platte pipeline, which interconnects with the Express pipeline in Casper, Wyoming, transports crude oil predominantly from the Bakken shale and western Canada to refineries in the Midwest.

Table of Contents

SESH

We have an effective 39% total investment in SESH through our ownership of SEP, an approximately 290-mile natural gas transmission system, with associated compressor stations, operated jointly by Spectra Energy and CenterPoint Energy Southeastern Pipelines Holding, LLC. SESH 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. SESH is owned 50% directly by SEP and 50% by Enable Midstream Partners, LP. Our investment in SESH is accounted for under the equity method of accounting.

Table of Contents

Market Hub

We have an effective 78% ownership interest in Market Hub through our ownership of SEP. Market Hub owns and operates two natural gas storage facilities, Moss Bluff and Egan, with a total storage capacity of approximately 47 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 ten pipeline systems, including the Texas Eastern system.

Saltville

We have an effective 78% ownership interest in Saltville through our ownership of SEP. 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.

Bobcat

We have an effective 78% ownership interest in Bobcat through our ownership of SEP. Bobcat, an approximately 30 Bcf salt dome facility, is strategically located on the Gulf Coast near Henry Hub, interconnecting with five major interstate pipelines, including Texas Eastern.

Steckman Ridge

We have an effective 39% investment in Steckman Ridge through our ownership of SEP. Steckman Ridge is an approximately 12 Bcf depleted reservoir storage facility located in south central Pennsylvania that interconnects with the Texas Eastern and Dominion Transmission, Inc. systems. Steckman Ridge is owned 50% directly by SEP and 50% by NJR Steckman Ridge Storage Company. Our investment in Steckman Ridge is accounted for under the equity method of accounting.

Competition

Spectra Energy Partners' natural gas transmission and storage businesses compete with similar facilities that serve our supply and market areas in the transmission and storage of natural gas. The principal elements of competition are location, rates, terms of service, and flexibility and reliability of service.

The natural gas transported 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.

Table of Contents

Spectra Energy Partners' crude oil transportation business competes with pipelines, rail, truck and barge facilities that transport crude oil from production areas to refinery markets. The principal elements of competition are location, rates, terms of service, flexibility and reliability of service.

Customers and Contracts

In general, Spectra Energy Partners' natural gas pipelines provide transmission 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. Transmission 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 the 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.

Spectra Energy Partners also provides interruptible transmission 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 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. Customers on the Express-Platte system are primarily refineries located in the Rocky Mountain and Midwestern states of the U.S. Other customers include oil producers and marketing entities. Express capacity is typically contracted under long-term committed contracts where customers reserve capacity and pay commitment charges based on a contracted volume even if they do not ship. A small amount of Express capacity and all Platte capacity is used by uncommitted shippers who only pay for the pipeline capacity that is actually used in a given month.

Table of Contents

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 transmission services to customers at the Dawn Hub, the largest integrated 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 U.S.

Union Gas' distribution system consists of approximately 40,000 miles of main and service pipelines. Distribution pipelines carry natural gas from the point of local supply to customers. Union Gas' underground natural gas storage facilities have a working capacity of approximately 163 Bcf in 25 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.

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 basis of price, terms of service, and flexibility and reliability of service. 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.

Table of Contents

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 transmission 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.

Table of Contents

WESTERN CANADA TRANSMISSION & PROCESSING

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

BC Pipeline and BC Field Services provide fee-based natural gas transmission and gas gathering and processing services. BC Pipeline is regulated by the 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.

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 eight gas processing plants located in BC, associated field compressor stations and approximately 1,400 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 800 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 U.S. Assets include a majority ownership interest in an NGL extraction plant, an integrated NGL fractionation facility, an NGL transmission pipeline, ten 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.

We own approximately 78% of M&N Canada, with affiliates of Emera, Inc. and Exxon Mobil Corporation directly owning the remaining 13% and 9% interests, respectively. M&N Canada is an approximately 550-mile mainline interprovincial natural gas transmission system which extends from Goldboro, Nova Scotia to the U.S. border near Baileyville, Maine. M&N Canada is connected to the U.S. portion of the Maritimes & Northeast Pipeline system, M&N U.S., which is directly owned by SEP (part of our Spectra Energy Partners segment) and affiliates of Emera, Inc. and Exxon Mobil Corporation. M&N Canada facilities include associated compressor stations and have a market delivery capability of approximately 0.6 Bcf/d of natural gas. The pipeline’s location and key interconnects with Spectra Energy’s transmission system link regional natural gas supplies to the northeast U.S. and Atlantic Canadian markets.

Table of Contents

Competition

Western Canada Transmission & Processing businesses compete with third-party midstream companies, exploration and production companies, and pipelines in the gathering, processing and transmission of natural gas and the extraction and marketing of NGL products. The principal elements of competition are location, rates, terms of service, and flexibility and reliability of service.

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 Nova Gas Transmission Ltd. (Nova/TransCanada) pipeline system. To extract and acquire NGLs, we must be competitive in the prices or fees we pay to gas shippers and suppliers. We also compete with other NGL marketers in the various product sales markets we serve.

Customers & Contracts

BC Pipeline provides: (i) transmission 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 transmission services to the nearest natural gas trading hub; and (ii) transmission services primarily to downstream markets in the Pacific Northwest (both in the U.S. and Canada) using the southern portion of the transmission pipeline and markets in Alberta through pipeline interconnects in northern BC with Nova/TransCanada. 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 transmission 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.

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 Nova/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. We further compete with other NGL extraction facilities to purchase and ship natural gas to our extraction and separation plant at Empress where we extract NGLs before selling the residue natural gas. 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 is 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. Empress' customers are U.S.-based and Canadian-based.

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.

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. In 2014, we implemented a commodity hedging program at Empress in an effort to mitigate a large portion of commodity risk.

Table of Contents

FIELD SERVICES

Field Services consists of our 50% investment in DCP Midstream, which is accounted for as an equity investment. DCP Midstream gathers, compresses, treats, processes, transports, stores and sells natural gas. In addition, this segment produces, fractionates, transports, stores and sells NGLs, recovers and sells condensate and trades and markets natural gas and NGLs. Phillips 66 owns the other 50% interest in DCP Midstream. DCP Midstream currently owns an approximate 21% interest in DCP Midstream Partners, LP (DCP Partners), a publicly traded master limited partnership which trades on the NYSE under the symbol "DPM." As its general partner, DCP Midstream accounts for its investment in DCP Partners as a consolidated subsidiary.

On October 30, 2015, Spectra Energy contributed our 33.3% interests in Sand Hills and Southern Hills NGL pipelines to DCP Midstream. See Part II. Item 8. Financial Statements and Supplementary Data, Note 3 of Notes to Consolidated Financial Statements for further discussion of this transaction.

DCP Midstream owns or operates assets in 17 states in the U.S. 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 operates in a diverse number of regions, including the Permian Basin, Eagle Ford, Niobrara/DJ Basin and Midcontinent. DCP Midstream owns or operates approximately 67,000 miles of gathering and transmission pipeline.

As of December 31, 2015, DCP Midstream owned or operated 64 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, 2015, DCP Midstream owned or operated 12 fractionators. In addition, DCP Midstream operates a propane wholesale marketing business and a eight million barrel propane and butane storage facility in the northeastern U.S.

The residue natural gas (gas that has had associated NGLs removed) 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

Table of Contents

individual consumers. DCP Midstream also stores residue natural gas at its 12 Bcf Southeast Texas 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 Southeast Texas storage facility and various intrastate pipelines which provide access to market centers/hubs such as Katy, Texas and the Houston Ship Channel.

DCP Midstream's operating results are significantly affected by changes in average NGL, natural gas and crude oil prices, which have declined substantially. 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 arrangements offered by the gatherer/processor and the ability of the gatherer/processor to obtain a satisfactory price for the producer's residue natural 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 NGLs to Phillips 66 and Chevron Phillips Chemical Company LLC (CPChem). In addition, DCP Midstream purchases NGLs from CPChem. Prior to December 31, 2014 approximately 35% of DCP Midstream's NGL production was committed to Phillips 66 and CPChem under 15-year contracts, the primary production commitment of which began a ratable wind down period in December 2014 and expires in January 2019. Approximately 28% of DCP Midstream's NGL production was committed to Phillips 66 and CPChem as of December 31, 2015. DCP Midstream anticipates continuing to purchase and sell commodities with Phillips 66 and CPChem, 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 75% 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 by DCP Midstream from the sale of the residue natural gas, NGLs and condensate, or an agreed-upon percentage of the proceeds based on index-related prices or contractual recoveries for the natural gas, NGLs and condensate, regardless of the actual amount of sales proceeds which DCP Midstream receives. DCP Midstream keeps the difference between the proceeds received and the amount remitted back to the producer. Under percentage-of-liquids arrangements, DCP Midstream does not keep any amounts related to the residue natural gas proceeds and only keeps amounts related to the difference between the proceeds received and the amount remitted back to the producer related to NGLs and condensate. Certain of these arrangements may also result in the producer retaining title to all or a portion of the residue natural gas and/or the NGLs in lieu of DCP Midstream returning sales proceeds to the producer. Additionally, these arrangements may include fee-based components. DCP Midstream's revenues from percentage-of-proceeds/index arrangements are directly related to the prices of natural gas, NGLs or condensate. DCP Midstream's revenues under percentage-of-liquids arrangements are directly related to the price of NGLs and condensate.

Fee-based arrangements. DCP Midstream receives a fee or fees for one or more of the following services: gathering, compressing, treating, processing, transporting or storing natural gas, and fractionating, storing and transporting NGLs. Fee-based arrangements include natural gas arrangements pursuant to which DCP Midstream obtains 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 transportation fees it would otherwise charge for transportation of 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 flows through its systems and is not dependent on commodity prices.

Table of Contents

However, to the extent that a sustained decline in commodity prices results in a decline in volumes, DCP Midstream's revenues from these arrangements would be reduced.

Keep-whole and wellhead purchase arrangements. DCP Midstream gathers raw natural gas from producers for processing, the NGLs and condensate are sold and the residue natural gas is returned to the producer with a British thermal unit (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 natural gas at market prices. Under these types of contracts, 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. DCP Midstream benefits in periods when NGL prices are higher relative to natural gas prices, where that frac spread exceeds our cost.

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.

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, pumps, 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 U.S. and Canada. Our supply chain management group uses economies-of-scale to maximize the efficiency of supply networks where applicable. The price of equipment and materials may vary however, perhaps substantially, from year to year. DCP Midstream performs its own supply chain management function.

Regulations

Most of our U.S. gas transmission, crude oil pipeline and storage operations are regulated by the FERC. The FERC regulates natural gas transmission in U.S. interstate commerce including the establishment of rates for services. The FERC also regulates the construction of U.S. interstate natural gas pipelines and storage facilities, including the extension, enlargement and abandonment of facilities. In addition, certain operations are subject to oversight by state regulatory commissions. To the extent that the natural gas intrastate pipelines that transport or store natural gas in interstate commerce provide services under Section 311 of the Natural Gas Policy Act of 1978, they are subject to FERC regulations. 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 transmission of gas by intrastate pipelines.

Our Spectra Energy Partners 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 (DOT) concerning pipeline safety.

Express-Platte pipeline system rates and tariffs are subject to regulation by the NEB in Canada and the FERC in the U.S. In addition, the Platte pipeline also operates as an intrastate pipeline in Wyoming and is subject to jurisdiction by the Wyoming Public Service Commission.

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.

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 Regulator and the Ontario Technical Standards and Safety Authority.

Our Canadian natural gas transmission and distribution operations 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

Table of Contents

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 business is not under any form of rate 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.

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 (BC), 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, 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 (The Act) which, as of 2007, required certain facilities to meet reductions in emission intensity. The Act was applicable to our Empress facility in Alberta beginning in 2008.

Table of Contents

The Canadian Environmental Assessment Act, 2012 (CEAA 2012) requires the NEB to consider potential environmental effects in their decisions for designated projects. The NEB under its enabling statute also conducts environmental assessments for projects that are not specifically designated under CEAA 2012. In either case, prior to receiving an approval to construct or operate a federally-regulated pipeline or facility, the NEB must consider a series of environmental factors, in particular whether the project has the potential to have adverse environmental effects. These types of assessments occur in relation to both maintenance and capital projects.

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, provincial 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 6,000 employees as of December 31, 2015, including approximately 3,600 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, 2016.

Table of Contents

Executive and Other Officers

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

Name	Age	Position
Gregory L. Ebel	51	President and Chief Executive Officer, Director
J. Patrick Reddy	63	Chief Financial Officer
Dorothy M. Ables	58	Chief Administrative Officer
Guy G. Buckley	55	Chief Development Officer
Julie A. Dill	56	Chief Communications Officer
Reginald D. Hedgebeth	48	General Counsel
William T. Yardley	51	President, U.S. Transmission and Storage
Allen C. Capps	45	Vice President and Controller
Laura Buss Sayavedra	48	Vice President and Treasurer

Gregory L. Ebel assumed his current position as President and Chief Executive Officer in January 2009. He previously served as Group Executive and Chief Financial Officer since January 2007. Mr. Ebel currently serves as the Chairman of the Board of Directors of Spectra Energy Corp and on the Board of Directors of Spectra Energy Partners GP, LLC and 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 2000 to 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. Ms. Ables currently serves on the Board of Directors of Spectra Energy Partners GP, LLC.

Guy G. Buckley assumed his current position as Chief Development Officer in January 2014. He previously served as Treasurer and Group Vice President-Mergers and Acquisitions from January 2012 to December 2013, and as Group Vice President, Corporate Strategy and Development from December 2008 to December 2011. Mr. Buckley currently serves on the Board of Directors of DCP Midstream, LLC.

Julie A. Dill assumed her current position as Chief Communications Officer January 2014. Ms. Dill previously served as Group Vice President-Strategy from January 2012 to December 2013, as President and Chief Executive Officer of Spectra Energy Partners, GP, LLC from January 2012 to October 2013 and as President of Union Gas Limited from December 2006 through December 2011. Ms. Dill currently serves on the Board of Directors of Spectra Energy Partners GP, LLC.

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. William T. Yardley assumed his current position as President, U.S. Transmission and Storage in January 2013. Prior to then, he served as Group Vice President of Northeastern U.S. Assets and Operations since 2007. Mr. Yardley currently serves on the Board of Directors of Spectra Energy Partners GP, LLC.

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.

Laura Buss Sayavedra assumed her current position as Vice President and Treasurer January 2014. Ms. Sayavedra previously served as Vice President-Strategy from March 2013 to December 2013, as Vice President and Chief Financial Officer of Spectra Energy Partners, GP, LLC from July 2008 to February 2013, and as Vice President, Strategic Development and Analysis of Spectra Energy Corp from January 2007 to June 2008.

Table of Contents

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 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 website at <http://www.spectraenergy.com>. Such reports are accessible at no charge through our website 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 oil, and low market prices of commodities adversely affect our operations and cash flows.

Our regulated businesses are generally economically stable; they are not significantly affected in the short-term by changing commodity prices. However, our businesses can all 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, oil and NGLs. These factors 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 could reduce the volume of natural gas and NGLs transported and distributed or gathered and processed at our plants, and the volume of oil transported, 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, resulting in the non-renewal of long-term contracts at the time of expiration. Lower demand along with lower prices for natural gas, oil 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, resulting in lower energy usage for heating or cooling purposes, respectively;
- supply of and demand for energy commodities, including any decrease in the production of natural gas and oil 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 and oil resources may cause customers to seek alternative energy resources, which could materially affect our revenues, earnings and cash flows.

Our natural gas and oil businesses are dependent on the continued availability of natural gas and oil production and reserves. Prices for natural gas and oil, regulatory limitations on the development of natural gas and oil 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 and oil 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 2015 would have resulted in an estimated net gain on the translation of local currency earnings of approximately \$24 million on our Consolidated Statement of Operations. In addition, if a 10% devaluation had occurred on December 31, 2015, the Consolidated Balance Sheet would have been negatively impacted by \$356

million through a cumulative translation adjustment in Accumulated Other Comprehensive Income (AOCI). At December 31, 2015, one U.S. dollar translated into 1.38 Canadian dollars.

Table of Contents

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 in our Western Canada Transmission & Processing segment, and to oil primarily in our Field Services segment. The effect of commodity price fluctuations on our earnings could be material. Effective January 2014, we implemented a commodity hedging program at Empress in order to manage risks associated with Empress' commodity price fluctuations. The commodity hedging program helps manage the fluctuations in the Conway/Mont Belvieu index prices. However, it does not manage potential fluctuations in pricing differentials between the Empress market and index prices. The changes in pricing differentials may be material and may adversely affect results.

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 revenues, operations and costs.

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

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

Execution of our capital projects subjects us to construction risks, increases in labor and material costs, and other risks that may 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;
- 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

Table of Contents

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, natural gas transmission and storage, crude oil transportation and storage, and gas 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, and crude oil transportation and storage, 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.

Our operations 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 laws and regulations administered by the Pipeline and Hazardous Materials Safety Administration (PHMSA) of the DOT. 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.

PHMSA is designing an Integrity Verification Process intended to create standards to verify maximum allowable operating pressure, and to improve and expand integrity management processes. There remains uncertainty as to how these standards will be implemented, but it is expected that the changes will impose additional costs on new pipeline projects as well as on existing operations. 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 an adverse effect on our operations, earnings, financial condition and cash flows.

In Canada, our interprovincial and international pipeline operations are subject to pipeline safety regulations overseen by the NEB. Applicable legislation and regulation require us to comply with a significant set of requirements for the design, construction, maintenance and operation of our interprovincial and international pipelines. Among other obligations, this regulatory framework imposes requirements to monitor and maintain the integrity of our pipelines. As in the U.S., several legislative changes addressing pipeline safety in Canada have recently come into force. The changes evidence an increased focus on the implementation of management systems to address key areas such as emergency management, integrity management, safety, security and environmental protection. Other legislative changes have created authority for the NEB to impose administrative monetary penalties for non-compliance with the regulatory regime it administers.

Compliance with these legislative changes may impose additional costs on new Canadian pipeline projects as well as on existing operations. Failure to comply with applicable regulations could result in a number of consequences which may have an adverse effect on our operations, earnings, financial condition and cash flows.

Our operations are subject to numerous environmental laws and regulations, compliance with which may require significant capital expenditures, increase our cost of operations and 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

Table of Contents

arising out of contaminated properties. In particular, compliance with major Clean Air Act regulatory programs is likely to cause us to incur significant capital expenditures to obtain permits, evaluate offsite impacts of our operations, install pollution control equipment, and otherwise assure compliance. Some states in which we operate are implementing new emissions limits to comply with 2008 ozone standards regulated under the National Ambient Air Quality Standards. In 2015, the ozone standards were lowered even further from 75 ppb to 70 ppb, which may require states to implement additional emissions regulations. 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.

In the U.S., climate change action is evolving at state, regional and federal levels. The Supreme Court decision in *Massachusetts v. EPA* in 2007 established that greenhouse gas (GHG) emissions were pollutants subject to regulation under the Clean Air Act. Pursuant to federal regulations, we are currently subject to an obligation to report our GHG emissions at our largest emitting facilities, but are not generally subject to limits on emissions of GHGs, (except to the extent that some GHGs consist of volatile organic compounds and nitrous oxides that are subject to emission limits). Proposed regulation may extend our reporting obligations to additional facilities and activities. In addition, a number of Canadian provinces and U.S. states have joined regional GHG initiatives, and a number are developing their own programs that would mandate reductions in GHG emissions. Public interest groups and regulatory agencies are increasingly focusing on the emission of methane associated with natural gas development and transmission as a source of 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. For its part, Canada has reaffirmed its strong preference for a harmonized approach with that of the U.S. While federal GHG related regulatory design details remain forthcoming, provincial authorities have been actively pursuing related initiatives.

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 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. Costs we may incur to comply with environmental regulations in the future may have a significant effect on our earnings and cash flows.

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.

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

Table of Contents

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 and crude oil transportation businesses 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. A significant amount of our credit exposures for transmission, 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 and oil producers may be the primary customer, our credit exposure with below investment-grade customers may increase. 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 BC 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 BC 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 BC and Alberta, 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, various aboriginal groups in Ontario have claimed aboriginal and treaty rights in areas where Union Gas' facilities, and the gas supply areas served by those facilities, are 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, including cyber-terrorism, 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 U.S. and its allies could be directed against companies operating in the U.S. This risk is particularly relevant for companies, like ours, operating in any energy infrastructure industry that handles volatile gaseous and liquid hydrocarbons. The potential for terrorism, including cyber-terrorism, has subjected our operations to increased risks that could have an adverse effect on our

business. In particular, we may experience increased capital and operating costs to implement increased security for our facilities and pipelines, such as additional physical facility and pipeline security, and additional security personnel. Moreover, any physical damage to high profile facilities resulting from acts of terrorism may not be covered, or covered fully, by insurance. We may be required to expend material amounts of capital to repair any facilities, the expenditure of which could affect our business and cash flows. A

Table of Contents

cyber attack could also lead to a significant interruption in our operations or unauthorized release of confidential or otherwise protected information, which could damage our reputation or lead to financial losses.

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, 2015, we had over 100 primary facilities located in the U.S. and Canada. We generally own sites associated with our major pipeline facilities, such as compressor stations. However, we generally operate our 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, 2015.

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 and Chatham, Ontario. For a description of our material properties, see Item 1. Business.

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.

Table of Contents

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 NYSE under the symbol "SE." As of January 31, 2016, there were approximately 107,000 holders of record of our common stock and approximately 566,000 beneficial owners.

Common Stock Data by Quarter

	Dividends Per Common Share	Stock Price Range (a)	
		High	Low
2015			
First Quarter	\$ 0.370	\$36.90	\$32.43
Second Quarter	0.370	38.47	32.19
Third Quarter	0.370	32.84	25.22
Fourth Quarter	0.370	30.55	21.43
2014			
First Quarter	\$ 0.335	\$38.73	\$34.23
Second Quarter	0.335	42.61	37.17
Third Quarter	0.335	43.12	38.55
Fourth Quarter	0.370	40.00	32.50

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