Spectra Energy Partners, LP
Form 10-K
February 27, 2015
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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
Form 10-K
x ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2014
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 001-33556
SPECTRA ENERGY PARTNERS, LP
(Exact name of registrant as specified in its charter)

Delaware	41-2232463
(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 Units Representing Limited Partner Interests	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None.
Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes x No ¨
Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act. Yes ¨ No x
Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports) and (2) has been subject to such filing requirements for the past 90 days. Yes x No ¨
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No ¨
Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. x
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer," and "smaller reporting company" in Rule 12b-2 of the Exchange Act.
Large accelerated filer x Accelerated filer ¨ Non-accelerated filer ¨ Smaller reporting company ¨

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

Estimated aggregate market value of the Common Units held by non-affiliates of the registrant at June 30, 2014: $2,689,000,000.

At January 31, 2015, there were 294,864,823 Common Units and 6,017,649 General Partner Units outstanding.

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

This document includes “forward-looking statements” within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Forward-looking statements represent management’s intentions, plans, expectations, assumptions and beliefs about future events. These forward-looking statements are identified by terms and phrases such as: anticipate, believe, intend, estimate, expect, continue, should, could, may, plan, project, predict, will, potential, forecast, and similar expressions. Forward-looking statements are subject to risks, uncertainties and other factors, many of which are outside our control and could cause actual results to differ materially from the results expressed or implied by those forward-looking statements. Factors used to develop these forward-looking statements and that could cause actual results to differ materially from those indicated in any forward-looking statement include, but are not limited to:

- state, 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 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;
- growth in opportunities, including the timing and success of efforts to develop U.S. and Canadian pipeline, storage, gathering and other related infrastructure projects and the effects of competition;
- the performance of natural gas transmission, storage and gathering facilities, and crude oil transportation and storage;
- the extent of success in connecting natural gas and oil supplies to transmission and gathering 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 Partners, LP has described. Spectra Energy Partners, LP undertakes no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

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PART I

Item 1. Business.

The terms “we,” “our,” “us,” and “Spectra Energy Partners” as used in this report refer collectively to Spectra Energy Partners, LP 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 Partners.

General

Spectra Energy Partners, LP, through its subsidiaries and equity affiliates, is engaged in the transmission, storage and gathering of natural gas, the transportation and storage of crude oil, and the transportation of natural gas liquids (NGLs), through interstate pipeline systems with over 17,000 miles of transmission and transportation pipelines and the storage of natural gas in underground facilities with aggregate working gas storage capacity of approximately 166 billion cubic feet (Bcf) in the United States and Canada.

We own and operate natural gas transmission, gathering and storage assets, and crude oil transportation and storage assets in central, southern and eastern United States as well as western Canada. Through our investments in DCP Sand Hills Pipeline, LLC (Sand Hills) and DCP Southern Hills Pipeline, LLC (Southern Hills), we also are engaged in the transportation of NGLs. Our assets are strategically located in geographic regions of the United States and Canada where demand, primarily for natural gas used in electricity generation, and crude oil, is expected to increase steadily. We have a broad mix of customers, including local gas distribution companies (LDC), municipal utilities, interstate and intrastate pipelines, direct industrial users, electric power generators, marketers and producers, and exploration and production companies. Our interstate gas transmission pipeline and storage operations and our crude oil transportation and storage operations are regulated by either the Federal Energy Regulatory Commission (FERC), the U.S. Department of Transportation (DOT), or the National Energy Board (NEB) with the exception of Moss Bluff intrastate storage operations and Ozark gathering facilities which are subject to oversight by various state commissions.

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Our operations and activities are managed by our general partner, Spectra Energy Partners (DE) GP, LP, which in turn is managed by its general partner, Spectra Energy Partners GP, LLC, (the General Partner). The General Partner is wholly owned by a subsidiary of Spectra Energy Corp (Spectra Energy). Spectra Energy is a separate, publicly traded entity which trades on the New York Stock Exchange (NYSE) under the symbol “SE.” As of December 31, 2014, Spectra Energy and its subsidiaries collectively owned 82% of us and the remaining 18% was publicly owned.

In March 2013, Spectra Energy acquired 100% of the ownership interests in the Express-Platte crude oil pipeline system (Express-Platte) from third-parties. In August 2013, we acquired a 40% ownership interest in the U.S. portion of Express-Platte (Express US) and a 100% ownership interest in the Canadian portion of Express-Platte (Express Canada) (collectively, Express-Platte) from subsidiaries of Spectra Energy (the Express-Platte acquisition).

In November 2013, we acquired substantially all of Spectra Energy’s remaining U.S. transmission, storage and liquids assets, including Spectra Energy’s remaining 60% interest in Express US (the U.S. Assets Dropdown). The pipeline systems include Texas Eastern Transmission, LP (Texas Eastern), Algonquin Gas Transmission, L.L.C. (Algonquin), the remaining ownership interest in Express US, an additional 39% interest in Maritimes & Northeast L.L.C. (M&N U.S.), 33% interests in both Sand Hills and Southern Hills, an additional 1% interest in Gulfstream Natural Gas System, LLC (Gulfstream) and a 24.95% interest in Southeast Supply Header, LLC (SESH). The natural gas and crude oil storage businesses include Bobcat Gas Storage (Bobcat), the remaining 50% interest in Market Hub Partners Holding (Market Hub), a 49% interest in Steckman Ridge, LP (Steckman Ridge), and Texas Eastern's and Express-Platte's storage facilities.

On November 3, 2014, we completed the second of the three planned transactions related to the U.S. Assets Dropdown. This transaction consisted of acquiring an additional 24.95% ownership interest in SESH and an additional 1% interest in Steckman Ridge from Spectra Energy.

The remaining and final transaction, related to the U.S. Assets Dropdown is expected to occur in November 2015, and will consist of Spectra Energy's remaining 0.1% interest in SESH.

The Express-Platte acquisition and the U.S. Assets Dropdown have been accounted for as acquisitions under common control, resulting in the recast of our prior results. See Note 2 of Notes to Consolidated Financial Statements for further discussion of the transactions.

Businesses

We manage our business in two reportable segments: U.S. Transmission, and Liquids. The remainder of our business operations is presented as “Other,” and consists mainly of certain corporate costs. The following sections describe the operations of each of our businesses. For financial information on our business segments, see Note 4 of Notes to Consolidated Financial Statements.

U.S. Transmission

Our U.S. Transmission business primarily provides transmission, storage, and gathering of natural gas for customers in various regions of the northeastern and southeastern United States. Our pipeline systems consist of approximately 14,000 miles of pipelines with eight primary transmission systems: Texas Eastern, Algonquin, East Tennessee Natural Gas, LLC (East Tennessee), M&N U.S., Ozark Gas Transmission, L.L.C. (Ozark Gas Transmission), Big Sandy Pipeline, L.L.C (Big Sandy), Gulfstream and SESH. The pipeline systems in our U.S. Transmission business receive natural gas from major North American producing regions for delivery to their respective markets. A majority of contracted transportation volumes are under long-term firm service agreements, where customers reserve capacity in the pipeline. Interruptible services, where customers can use capacity if it is available at the time of the request, are provided on a short-term or seasonal basis.

U.S. Transmission provides natural gas storage services through Saltville Gas Storage Company L.L.C. (Saltville), Market Hub, Steckman Ridge, Bobcat and Texas Eastern’s facilities. Gathering services are provided through Ozark Gas Gathering, L.L.C. (Ozark Gas Gathering). In the course of providing transportation services, U.S. Transmission also processes natural gas on our Texas Eastern system.

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.

Actual throughput and storage injections/withdrawals do not have a significant effect on revenues or earnings.
Most of U.S. Transmission’s pipeline and storage operations are regulated by the FERC and are subject to the jurisdiction of various federal, state and local environmental agencies.

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Texas Eastern

The Texas Eastern natural gas transmission system extends approximately 1,700 miles from producing fields in the Gulf Coast region of Texas and Louisiana to Ohio, Pennsylvania, New Jersey and New York. It consists of two parallel systems, one with one to four large-diameter parallel pipelines and the other with one to three large-diameter parallel pipelines. Texas Eastern's onshore system consists of approximately 8,600 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 74 Bcf, owned by Market Hub and Bobcat.

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Algonquin

The Algonquin natural gas transmission system connects with Texas Eastern's facilities in New Jersey and extends approximately 250 miles through New Jersey, New York, Connecticut, Rhode Island and Massachusetts where it connects to M&N U.S. The system consists of approximately 1,130 miles of pipeline with associated compressor stations.

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East Tennessee

East Tennessee's natural gas transmission system crosses Texas Eastern's system at two locations in Tennessee and consists of two mainline systems totaling approximately 1,500 miles of pipeline in Tennessee, Georgia, North Carolina and Virginia, with associated compressor stations. East Tennessee has a liquefied natural gas (LNG, natural gas that has been converted to liquid form) storage facility in Tennessee with a total working capacity of 1 Bcf. East Tennessee also connects to the Saltville storage facilities in Virginia that have a working gas capacity of approximately 5 Bcf.

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Maritimes & Northeast Pipeline

We acquired 39% of M&N U.S. from Spectra Energy in 2012. On November 1, 2013, Spectra Energy contributed its remaining 39% ownership in M&N U.S. to us in the U.S. Assets Dropdown. M&N U.S. is owned 78% directly by us, 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, which is owned 78% by Spectra Energy. M&N U.S. facilities include compressor stations, with a market delivery capability of approximately 0.8 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.

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Ozark

Ozark Gas Transmission consists of an approximately 530-mile natural gas transmission system extending from southeastern Oklahoma through Arkansas to southeastern Missouri. Ozark Gas Gathering consists of an approximately 365-mile natural gas gathering system, with associated compressor stations, that primarily serves Arkoma basin producers in eastern Oklahoma.

On April 28, 2014, Ozark Gas Transmission entered into an agreement with Magellan Midstream Partners, L.P. (Magellan) to lease an approximately 159-mile stretch of natural gas pipeline to Magellan and perform the necessary conversion work to allow for the transportation of petroleum liquids. Ozark Gas Transmission expects to receive approval from the FERC and begin the necessary conversion work by mid-2015.

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Big Sandy

We acquired Big Sandy in 2011. 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.

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Gulfstream

We acquired 24.5% of Gulfstream in 2010 to increase our ownership to 49%. On November 1, 2013, Spectra Energy contributed its remaining 1% ownership in Gulfstream to us in the U.S. Assets Dropdown. 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 us and 50% by affiliates of Williams. Our investment in Gulfstream is accounted for under the equity method of accounting.

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SESH

SESH, an approximately 290-mile natural gas transmission system, with associated compressor stations, is operated jointly by Spectra Energy and CenterPoint Energy Southeastern Pipelines Holding, LLC (CenterPoint). 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 49.9% directly by us and 0.1% directly by Spectra Energy, with the remaining 50% owned by CenterPoint and Enable Midstream Partners, LP, collectively. Our investment in SESH is accounted for under the equity method of accounting.

Market Hub

Market Hub owns and operates two natural gas storage facilities, Moss Bluff and Egan, with a total storage capacity of approximately 48 Bcf. The Moss Bluff facility consists of four salt dome storage caverns located in southeast Texas, with access to five pipeline systems including the Texas Eastern system. The Egan facility consists of four salt dome storage caverns located in south central Louisiana, with access to eight pipeline systems, including the Texas Eastern system.

Saltville

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

Bobcat, an approximately 26 Bcf salt dome facility, is strategically located on the Gulf Coast near Henry Hub, interconnecting with five major interstate pipelines, including Texas Eastern.

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Steckman Ridge

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% by us and 50% by NJR Steckman Ridge Storage Company. Our investment in Steckman Ridge is accounted for under the equity method of accounting.

Competition

Our 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.

Customers and Contracts

In general, our natural gas pipelines provide transmission and storage services for 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.

We also provide 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.

Liquids

Our Liquids business provides transportation and storage of crude oil and transportation of NGLs for customers in central and southern United States and Canada. Our Liquids pipeline system contains more than 3,500 miles of pipelines with three primary systems: Express-Platte, Sand Hills and Southern Hills.

Most of Liquids' pipeline and storage operations are regulated by the FERC and the NEB, and are subject to the jurisdiction of various federal, state and local environmental agencies.

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Express-Platte

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.

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Sand Hills / Southern Hills

We own direct one-third ownership interests in Sand Hills and Southern Hills. DCP Midstream Partners, LP (DCP Partners) (DCP Midstream, LLC's (DCP Midstream) publicly traded master limited partnership), a 50% owned equity affiliate of Spectra Energy, and Phillips 66 also each own a direct one-third interest in each of the two pipelines. Our investments in Sand Hills and Southern Hills are accounted for under the equity method of accounting.

The Sand Hills pipeline is an approximately 900 mile pipeline engaged in the business of transporting NGLs and provides takeaway service from the Permian and Eagle Ford basins to fractionation facilities along the Texas Gulf Coast and the Mont Belvieu, Texas market hub. The Southern Hills pipeline is also an approximately 900 mile pipeline engaged in the business of transporting NGLs and provides takeaway service from the Midcontinent to fractionation facilities along the Texas Gulf Coast and the Mont Belvieu, Texas market hub. The Sand Hills and Southern Hills pipelines were placed into service in the second quarter of 2013.

Competition

Our 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.

In transporting NGLs, Sand Hills and Southern Hills compete with a number of major interstate and intrastate pipelines, including those affiliated with major integrated oil companies, and rail and truck fleet operations. In general, Sand Hills and Southern Hills compete with these entities in terms of transportation fees, reliability and quality of customer service.

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Customers and Contracts

Customers on the Express-Platte system are primarily refineries located in the Rocky Mountain and Midwestern states of the United States. 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.

Sand Hills and Southern Hills generate the majority of their revenues from fee-based arrangements. The revenues earned by Sand Hills and Southern Hills are for long-term contracts relating to the transportation of NGLs and generally are not dependent on commodity 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, gas meters and other consumables.

We utilize Spectra Energy’s supply chain management function which operates a North American supply chain management network. The supply chain management group uses the economies-of-scale of Spectra Energy to maximize the efficiency of supply networks where applicable. The price of equipment and materials may vary however, perhaps substantially, from year to year.

Regulations

Most of our U.S. gas transmission, crude oil transportation pipeline and storage operations are regulated by the FERC. The FERC regulates natural gas transmission and crude oil transportation 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 gas transmission and storage 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 interstate natural gas pipelines are also subject to the regulations of the 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 United States. In addition, the Platte pipeline also operates as an intrastate pipeline in Wyoming and is subject to jurisdiction by the Wyoming Public Service Commission.

Under current policy, the FERC permits pipelines and storage companies to include a tax allowance in the cost-of-service used as the basis for calculating their regulated rates. For pipelines and storage companies owned by partnerships or limited liability company interests, the tax allowance will reflect the actual or potential income tax liability on the FERC jurisdictional income attributable to all partnership or limited liability company interests if the ultimate owner of the interest has an actual or potential income tax liability on such income. This policy was upheld in 2007 by the Court of Appeals for the District of Columbia Circuit. Whether the owners of a pipeline or storage company have such actual or potential income tax liability will be reviewed by the FERC on a case-by-case basis. In a future rate case, the pipelines and storage companies in which we own an interest may be required to demonstrate the extent to which inclusion of an income tax allowance in the applicable cost-of-service is permitted under the current income tax allowance policy. Some entities have authority to charge market-based rates and therefore this tax allowance issue does not affect the rates that they charge their customers.

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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 transmission, storage and gathering 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 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.

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 16 of Notes to Consolidated Financial Statements.

Except to the extent discussed in Notes 5 and 16, 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 partnership 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 Notes 4 and 15 of Notes to Consolidated Financial Statements.

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Employees

We do not have any employees. We are managed by the directors and officers of our general partner. As of December 31, 2014, our general partner and its affiliates have approximately 2,300 employees performing services for our operations, and are solely responsible for providing the employees and other personnel necessary to conduct our operations.

Our Partnership Agreement

Set forth below is a summary of the provisions of our partnership agreement that relate to available cash and operating surplus:

Available Cash. For any quarter ending prior to liquidation:

(a) the sum of:

(1) all cash and cash equivalents of the partnership and our subsidiaries on hand at the end of that quarter; and

(2) if our general partner so determines, all or a portion of any additional cash or cash equivalents of our partnership and our subsidiaries on hand on the date of determination of Available Cash for that quarter;

(b) less the amount of cash reserves established by our general partner to:

(1) provide for the proper conduct of the business of the partnership and our subsidiaries (including reserves for future capital expenditures and for future credit needs of the partnership and our subsidiaries) after that quarter;

(2) comply with applicable law or any debt instrument or other agreement or obligation to which we or any of our subsidiaries or a part of our assets are subject; and

(3) provide funds for minimum quarterly distributions and cumulative common unit arrearages for any one or more of the next four quarters;

provided, however, that our general partner may not establish cash reserves pursuant to clause (b)(3) immediately above unless our general partner has determined that the establishment of reserves will not prevent us from distributing the minimum quarterly distribution on all common units and any cumulative common unit arrearages thereon for that quarter; and provided, further, that disbursements made by us or any of our subsidiaries or cash reserves established, increased or reduced after the end of that quarter but on or before the date of determination of Available Cash for that quarter shall be deemed to have been made, established, increased or reduced, for purposes of determining Available Cash, within that quarter if our general partner so determines.

Operating Surplus. For any period prior to liquidation, on a cumulative basis and without duplication:

(a) the sum of:

(1) all cash receipts of our partnership and our subsidiaries for the period beginning on the closing date of our initial public offering and ending with the last day of the period, other than cash receipts from interim capital transactions; and

(2) an amount equal to the sum of (A) two times the amount needed for any one quarter for us to pay the minimum quarterly distribution on all units (including the general partner units) and (B) two times the amount in excess of the minimum quarterly distribution for any quarter to pay a distribution on all Common Units at the same per unit amount as was distributed on the Common Units in excess of the minimum quarterly distribution in the immediately preceding quarter, provided the amount in (B) will be deemed to be Operating Surplus only to the extent that the distribution paid in respect of such amounts is paid on Common Units, less

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(b) the sum of:
(1) operating expenditures for the period beginning on the closing date of our initial public offering and ending with the last day of that period; and
(2) the amount of cash reserves (or our proportionate share of cash reserves in the case of subsidiaries that are not wholly owned) established by our general partner to provide funds for future operating expenditures; provided however, that disbursements made (including contributions to us or our subsidiaries or disbursements on behalf of us or our subsidiaries) or cash reserves established, increased or reduced after the end of that period but on or before the date of determination of Available Cash for that period shall be deemed to have been made, established, increased or reduced for purposes of determining operating surplus, within that period if our general partner so determines.

Additional Information

We were formed on March 19, 2007 as a Delaware master limited partnership. 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 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 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.spectraenergypartners.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.

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Item 1A. Risk Factors.

Discussed below are the material risk factors relating to us.

Risks Related to our Business

We may not have sufficient cash from operations to enable us to make cash distributions to common unitholders.

In order to make cash distributions at our minimum distribution rate of $0.30 per common unit per quarter, or $1.20 per unit per year, we will require Available Cash of approximately $90 million per quarter, or $361 million per year, depending on the actual number of common units outstanding. We may not have sufficient Available Cash from operating surplus each quarter to enable us to make cash distributions at the minimum distribution rate. The amount of cash we can distribute on our units principally depends upon the amount of cash we generate from operations, which will fluctuate based on, among other things:

- the rates charged to, and the volumes contracted by customers for natural gas transmission, storage and gathering services and crude oil transportation;
- the overall demand for natural gas in the southeastern, mid-Continent, and Northeast regions of the United States, and the quantities of natural gas available for transport, especially from the Gulf of Mexico, Appalachian and mid-Continent areas, as well as the overall demand for crude oil in central and southern United States and Canada;
- regulatory action affecting the demand for natural gas and crude oil, the supply of natural gas and crude oil, the rates we can charge, contracts for services, existing contracts, operating costs and operating flexibility;
- changes in environmental, safety and other laws and regulations;
- regulatory and economic limitations on the development of import and export LNG terminals in the Gulf Coast region; and
- the level of operating and maintenance, and general and administrative costs.

In addition, the actual amount of Available Cash will depend on other factors, some of which are beyond our control, including:

- the level of capital expenditures to complete construction projects;
- the cost and form of payment of acquisitions;
- debt service requirements and other liabilities;
- fluctuations in working capital needs;
- the ability to borrow funds and access capital markets;
- restrictions on distributions contained in debt agreements; and
- the amount of cash reserves established by our general partner.

Our subsidiaries and equity affiliates conduct operations and own our operating assets, which may affect our ability to make distributions to our unitholders. In addition, we cannot control the amount of cash that will be received from our equity investments, and we may be required to contribute significant cash to fund their operations.

We are a partnership holding company and our operating subsidiaries conduct all of our operations and own all of our operating assets. We have no significant assets other than the ownership interests in our subsidiaries and our equity investments. As a result, our ability to make distributions to our unitholders depends on the performance of these subsidiaries and equity investments and their ability to distribute funds to us. The ability of our subsidiaries and equity investments to make distributions to us may be restricted by, among other things, the provisions of existing and future indebtedness, applicable state partnership and limited liability company laws and other laws and regulations, including FERC policies.

Our equity investments generated approximately 16% of our distributable cash flow in 2014. Spectra Energy operates Steckman Ridge. Spectra Energy shares operations of SESH with CenterPoint and shares operations of Gulfstream with Williams. The operations of Sand Hills and Southern Hills are conducted by DCP Midstream. Accordingly, we do not control the amount of cash distributed to us nor do we control ongoing operational decisions, including the incurrence of capital expenditures that we may be required to fund.

Our lack of control over the operations of our equity investments may mean that we do not receive the amount of cash we expect to be distributed to us. In addition, we may be required to provide additional capital, and these contributions may be

material. The equity affiliates are not prohibited from incurring indebtedness by the terms of their respective limited liability company agreement and general partnership agreements. If they were to incur significant additional indebtedness, it could inhibit their respective abilities to make distributions to us. This lack of control may significantly and adversely affect our ability to distribute cash.

Our natural gas pipeline systems, crude oil transportation pipeline systems and certain of our storage facilities and related assets are subject to regulation by the FERC and the NEB, which could have an adverse effect on our ability to establish transmission, transportation, storage and gathering rates that would allow us to recover the full cost of operating our pipelines, including a reasonable return, and our ability to make distributions.

Our natural gas pipeline systems, crude oil transportation pipeline systems and certain of our storage facilities and related assets are subject to regulation by the FERC and the NEB. The regulators have authority to regulate natural gas pipeline transmission and crude oil pipeline transportation services, including; the rates charged for the services, terms and conditions of service, certification and construction of new facilities, the extension or abandonment of services and facilities, the maintenance of accounts and records, the acquisition and disposition of facilities, the initiation and discontinuation of services, and various other matters.

Action by the FERC and the NEB on currently pending regulatory matters as well as matters arising in the future could adversely affect our ability to establish or charge rates that would cover future increase in their costs, such as additional costs related to environmental matters including any climate change regulation, or even to continue to collect rates that cover current costs, including a reasonable return. We cannot assure unitholders that our pipeline systems will be able to recover all of their costs through existing or future rates.

In addition, we cannot give assurance regarding the likely future regulations under which we will operate our natural gas transmission, crude oil transportation, storage and gathering businesses or the effect such regulation could have on our business, financial condition, results of operations or cash flows, including our ability to make distributions.

Certain transmission services are subject to long-term, fixed-price “negotiated rate” contracts that are not subject to adjustment, even if our cost to perform services exceeds the revenues received from such contracts, and, as a result, our costs could exceed our revenues received under such contracts.

Under FERC policy, a regulated service provider and a customer may mutually agree to sign a contract for service at a “negotiated rate” which may be above or below the FERC-regulated “recourse rate” for that service. For 2014, 49% of U.S. Transmission’s firm revenues were derived from such negotiated rate contracts. These negotiated rate contracts are not subject to adjustment for increased costs which could be produced by inflation or other factors relating to the specific facilities being used to perform the services. It is possible that the costs to perform services under these negotiated rate contracts will exceed the negotiated rates. If this occurs, it could decrease cash flows from U.S. Transmission.

Increased competition from alternative natural gas transmission, storage and gathering options and alternative fuel sources could have a significant financial effect on us.

We compete primarily with other interstate and intrastate pipelines, storage and gathering facilities in the transmission, storage and gathering of natural gas. Some of these competitors may expand or construct transmission, storage and gathering systems that would create additional competition for the services we provide to our customers. Moreover, Spectra Energy and its affiliates are not limited in their ability to compete with us. Further, natural gas also competes with other forms of energy available to our customers, including electricity, coal and fuel oils.

The principal elements of competition among natural gas transmission, storage and gathering assets are location, rates, terms of service, access to natural gas supplies, flexibility and reliability. The FERC’s policies promoting competition in natural gas markets are having the effect of increasing the natural gas transmission, storage and gathering options for our traditional customer base. As a result, we could experience some “turnback” of firm capacity as existing agreements expire. If our pipelines and storage facilities are unable to remarket this capacity or can remarket it only at substantially discounted rates compared to previous contracts, they may have to bear the costs associated with the turned back capacity. Increased competition could reduce the volumes of natural gas transported, stored or gathered by our systems or, in cases where we do not have long-term fixed rate contracts, could force us to lower our transmission, storage or gathering rates. Competition could intensify the negative effect of factors that significantly decrease demand for natural gas in the markets served by our pipeline systems, such as competing or alternative forms of energy, a recession or other adverse economic conditions, higher fuel costs and taxes or other governmental or regulatory actions that directly or indirectly increase the cost or limit the use of natural gas. Our ability to renew or replace existing contracts at rates sufficient to maintain current revenues and cash flows could be adversely affected

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by the activities of our competitors. All of these competitive pressures could have an adverse effect on our business, results of operations, financial condition or cash flows, including our ability to make distributions.

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 and gathering 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, including our ability to make distributions.

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.

If third-party pipelines and other facilities interconnected to our pipelines become unavailable to transport natural gas, our revenues and Available Cash could be adversely affected.

We depend upon third-party pipelines and other facilities that provide delivery options to and from our pipelines and storage facilities. Because we do not own these third-party pipelines or facilities, their continuing operation is not within our control. If these or any other pipeline connection were to become unavailable for current or future volumes of natural gas due to repairs, damage to the facility, lack of capacity or any other reason, our ability to operate efficiently and continue shipping natural gas to end-markets could be restricted, thereby reducing revenues. Any temporary or permanent interruption at any key pipeline interconnect could have an adverse effect on our business, results of operations, financial condition or cash flows, including our ability to make distributions.

If we do not complete expansion projects or make and integrate acquisitions our future growth may be limited.

A principal focus of our strategy is to continue to grow the cash distributions on our units by expanding our business. Our ability to grow depends on our ability to complete expansion projects and make acquisitions that result in an increase in cash generated. We may be unable to complete successful, accretive expansion projects or acquisitions for any of the following reasons:

- an inability to identify attractive expansion projects or acquisition candidates or we are outbid by competitors;
- an inability to obtain necessary rights-of-way or government approvals, including regulatory agencies;
- an inability to successfully integrate the businesses we build or acquire;
- we are unable to raise financing for such expansion projects or acquisitions on economically acceptable terms;
- incorrect assumptions about volumes, reserves, revenues and costs, including synergies and potential growth; or
- we are unable to secure adequate customer commitments to use the newly expanded or acquired facilities.

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

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

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We maintain a revolving credit facility to provide back-up for our commercial paper program, for borrowings and/or letters of credit. This facility requires us to maintain a consolidated leverage ratio of consolidated indebtedness to consolidated earnings from continuing operations before interest, taxes, and depreciation and amortization (EBITDA), as defined in the agreement. Failure to maintain this covenant could preclude us from issuing commercial paper or letters of credit or borrowing under the revolving credit facility which could affect cash flows or restrict business. Furthermore, if Spectra Energy Partner'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 facility, 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.

The enactment of climate change legislation or the adoption of regulations under the existing Clean Air Act could result in increased operating costs and delays in obtaining necessary permits for our capital projects.

The current international climate framework, the United Nations-sponsored Kyoto Protocol, prescribed specific targets to reduce GHG emissions for developed countries for the 2008-2012 period. The Kyoto Protocol expired in 2012 and had not been signed by the U.S.; however, at the Copenhagen Climate Change Summit in 2009, the U.S. indicated it would reduce carbon dioxide emissions by 17% below 2005 levels by 2020. The United Nations-sponsored international negotiations held in Durban, South Africa in 2011 resulted in a non-binding agreement (Durban Agreement) to develop a roadmap aimed at creating a global agreement on climate action to be implemented by 2020. The U.S. is a party to the Durban agreement. In the interim period before 2020, the Kyoto Protocol will continue in effect, although it is expected that not all of the current parties will choose to commit for this extended period.

In the 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 GHGs 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 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.

In 2010, the EPA issued the Prevention of Significant Deterioration (PSD) and the Title V Greenhouse Gas Tailoring Rule (Tailoring Rule). Beginning in 2011, the Tailoring Rule required that construction of new or modification of existing major sources of GHG emissions be subject to the PSD air permitting program (and later, the Title V permitting program), although the regulation also significantly increased the emissions thresholds that would subject facilities to these regulations. The scope of the Tailoring rule was limited by a 2015 U.S. Supreme Court decision, which determined that sources which are major sources only for GHGs (Step 2 sources) are no longer subject to the PSD permitting process. EPA followed with guidance indicating it will not enforce PSD permitting against these Step 2 sources. However, some states incorporated GHG permitting into their state regulations, and may continue to enforce these requirements. We anticipate that in the future, some new capital projects or projects to modify existing facilities could be subject to additional state-required permitting requirements related to GHG emissions that may result in delays in completing such projects. In 2014, the EPA proposed revising regulations to the National Ambient Air Quality Standards (NAAQS) that would lower the existing standard from 75 parts per billion (ppb) set in 2008, to a standard between 65 and 70 ppb. This may increase the non-attainment areas along our system and the number of affected facilities. These facilities may require pollution controls or replacement of equipment to comply with tightened standards and may face a less certain permitting process. In 2015, the Obama Administration issued its intention to regulate methane emissions from new and modified natural gas transmission and storage sources, and its expectation for voluntary emission decreases from existing sources. While uncertainty remains as to how this blueprint will be implemented, we anticipate that additional controls or costs may be incurred.

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Due to the speculative outlook regarding any U.S. federal and state 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 may incur significant costs and liabilities as a result of pipeline integrity management program testing and any necessary pipeline repair or preventative or remedial measures.

The DOT has adopted regulations requiring pipeline operators to develop integrity management programs for transmission pipelines located where a leak or rupture could do the most harm in "high consequence areas." The regulations require operators to:

- perform ongoing assessments of pipeline integrity;
- identify and characterize applicable threats to pipeline segments that could affect a high consequence area;
- improve data collection, integration and analysis;
- repair and remediate the pipeline as necessary; and
- implement preventive and mitigating actions.

Our actual implementation costs may be affected by industry-wide demand for the associated contractors and service providers. Additionally, should we fail to comply with DOT regulations, we could be subject to penalties and fines.

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.

In 2010, serious pipeline incidents on systems unrelated to ours focused the attention of Congress and the public on pipeline safety. Legislative proposals were introduced in Congress to strengthen PHMSA's enforcement and penalty authority, and expand the scope of its oversight. In August 2011, PHMSA initiated an Advance Notice of Proposed Rulemaking announcing its consideration of substantial revisions in its regulations to increase pipeline safety. In January 2012, the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 was signed into law. This Act (the 2012 PSA Amendments) amends the Pipeline Safety Act in a number of significant ways, including:

- Authorizing PHMSA to assess higher penalties for violations of its regulations;
- Requiring PHMSA to adopt appropriate regulations within two years requiring the use of automatic or remote-controlled shutoff valves on new or rebuilt pipeline facilities and to perform a study on the application of such technology to existing pipeline facilities in High Consequence Areas (HCAs);
- Requiring operators of pipelines to verify maximum allowable operating pressure and report exceedances within five days;
- Requiring PHMSA to study and report on the adequacy of soil cover requirements in HCAs; and
- Requiring PHMSA to evaluate in detail whether integrity management requirements should be expanded to pipeline segments outside of HCAs (where the requirements currently apply).

Many of these legislative changes, such as increasing penalties, have been completed, while others are substantially in progress with resolution expected in 2015. Additionally, Congress is tasked with reauthorization of the Pipeline Safety Act during fiscal year 2015. 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 or cash flows.

In Canada, our 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 pipeline. Among other obligations, this regulatory framework imposes requirements to monitor and maintain the integrity of our pipeline.

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.

Restrictions in our credit facility may limit our ability to make distributions and may limit our ability to capitalize on acquisition and other business opportunities.

The operating and financial restrictions and covenants in our credit facility and any future financing agreements could restrict our ability to finance future operations or capital needs or to expand or pursue business activities associated with our subsidiaries and equity investments. Our credit facility contains covenants that restrict or limit our ability to:

- make distributions if any default or event of default, as defined, occurs;
- make other restricted distributions or dividends on account of the purchase, redemption, retirement, acquisition, cancellation or termination of partnership interests;
- incur additional indebtedness or guarantee other indebtedness;
- grant liens or make certain negative pledges;
- make certain loans or investments;
- engage in transactions with affiliates;
- make any material change to the nature of our business from the midstream energy business;
- make a disposition of assets; or
- enter into a merger, consolidate, liquidate, wind up or dissolve.

The credit facility contains covenants requiring us to maintain certain financial ratios and tests. The ability to comply with the covenants and restrictions contained in the credit facility may be affected by events beyond our control, including prevailing economic, financial and industry conditions. If market or other economic conditions deteriorate, our ability to comply with these covenants may be impaired. If we violate any of the restrictions, covenants, ratios or tests in our credit facility, the lenders will be able to accelerate the maturity of all borrowings under the credit facility and demand repayment of amounts outstanding, the lenders' commitment to make further loans to us may terminate, and the operating partnership may be prohibited from making any distributions. We might not have, or be able to obtain, sufficient funds to make these accelerated payments. Any subsequent replacement of our credit facility or any new indebtedness could have similar or greater restrictions.

The credit and risk profile of our general partner and its owner, Spectra Energy, could adversely affect our credit ratings and risk profile, which could increase our borrowing costs or hinder our ability to raise capital.

The credit and business risk profiles of our general partner and Spectra Energy may be factors considered in credit evaluations of us. This is because our general partner controls our business activities, including our cash distribution policy, acquisition strategy and business risk profile. Another factor that may be considered is the financial condition of Spectra Energy, including the degree of its financial leverage and its dependence on cash flow from the partnership to service its indebtedness.

Our credit rating could be adversely affected by the leverage of our general partner or Spectra Energy, as credit rating agencies may consider the leverage and credit profile of Spectra Energy and its affiliates because of their ownership interest in and control of us, and the strong operational links between Spectra Energy and us. Any adverse effect on our credit rating would increase our cost of borrowing or hinder our ability to raise financing in the capital markets, which would impair our ability to grow our business and make distributions.

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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.

Protecting against potential terrorist activities requires significant capital expenditures and a successful terrorist attack could affect our business.

Acts of terrorism and any possible reprisals as a consequence of any action by the U. S. and its allies could be directed against companies operating in the U.S. This risk is particularly great for companies, like ours, operating in any energy infrastructure industry that handles volatile gaseous and liquid hydrocarbons. The potential for terrorism, 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 adversely affect our business and cash flows.

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

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 or gathered, and the volume of oil transported, resulting in lower earnings and cash flows. 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 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.

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

Our U.S. assets and operations are subject to regulation by various federal, state and local authorities, including regulation by the FERC and by various authorities under federal, state and local environmental laws. Our operations in Canada are subject to regulation by the NEB, and by 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 make distributions.

In addition, regulators in the U.S. 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.

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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; and
- the ability to construct projects within anticipated costs, including the risk of cost overruns resulting from inflation or increased costs of equipment, materials or labor, weather, geologic conditions or other factors beyond our control, that may be material; and
- general economic factors that affect the demand for natural gas infrastructure.

Any of these risks could prevent a project from proceeding, delay its completion or increase its anticipated cost. As a result, new facilities may not achieve their expected investment return, which could affect our earnings, financial position and cash flows.

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 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 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.

Our natural gas transmission, storage and gathering activities are subject to stringent and complex federal, state and local environmental laws and regulations, including air emissions, water quality, wastewater discharges, solid waste and hazardous waste. These laws and regulations can result in increased capital, operating and other costs. These laws and regulations generally require us to obtain and comply with a wide variety of environmental licenses, permits, inspections and other approvals. Compliance with environmental laws and regulations can require significant expenditures, including expenditures for cleanup costs and damages arising out of contaminated properties. In particular, compliance with major Clean Air Act regulatory programs may cause us to incur significant capital expenditures to obtain permits, evaluate offsite impacts of our operations, install pollution control equipment, and otherwise assure compliance.

The precise nature of these compliance obligations at each of our facilities has not been finally determined and may depend in part on future regulatory changes. In addition, compliance with new and emerging environmental regulatory programs is likely to significantly increase our operating costs compared to historical levels. Failure to comply with environmental regulations may result in the imposition of fines, penalties and injunctive measures affecting our operating assets. In addition, changes in environmental laws and regulations or the enactment of new environmental laws or regulations could result in a material increase in our cost of compliance with such laws and regulations. We may not be able to obtain or maintain from time to time all required environmental regulatory approvals for our operating assets or development projects. If there is a delay in obtaining any required environmental regulatory approvals, if we fail to obtain or comply with them or if environmental laws or regulations change or are administered in a more stringent manner, the operations of facilities or the development of new facilities could be prevented, delayed or become subject to additional costs. No assurance can be made that

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

Natural gas transmission and storage, NGL transmission, and crude oil transportation and storage activities involve numerous risks that may result in accidents or otherwise affect our operations.

There are a variety of hazards and operating risks inherent in natural gas gathering and processing, transmission and storage 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. Therefore, should any of these risks materialize, it could have a material effect on our business, earnings, financial condition and cash flows.

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. We may elect to self insure a portion of our asset portfolio. Moreover, we do not maintain offshore business interruption insurance. Therefore, should any of these risks materialize, it could have a material effect on our business, earnings, financial condition, results of operations or cash flows, including our ability to make distributions.

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 services are with customers who have an investment-grade rating (or the equivalent based on our evaluation) or are secured by collateral. However, we cannot predict to what extent our business would be impacted by deteriorating conditions in the economy, including possible declines in our customers' creditworthiness. As a result of future capital projects for which natural gas producers may be the primary customer, 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.

Risks Inherent in an Investment in Us

Spectra Energy controls our general partner, which has sole responsibility for conducting our business and managing our operations. Our general partner and its affiliates, including Spectra Energy, have conflicts of interest with us and limited fiduciary duties, and may favor their own interests to the detriment of us.

Spectra Energy owns and controls our general partner. Some of our general partner's directors, and some of its executive officers, are directors or officers of Spectra Energy or its affiliates. Although our general partner has a fiduciary duty to manage us in a manner beneficial to Spectra Energy and our unitholders, the directors and officers of our general partner have a fiduciary duty to manage our general partner in a manner beneficial to Spectra Energy. Therefore, conflicts of interest may arise between Spectra Energy and its affiliates, including our general partner, on the one hand, and us and our unitholders, on the other hand. In resolving these conflicts of interest, our general partner may favor its own interests and the interests of its affiliates over the interests of our unitholders. These conflicts include, among others, the following situations:

- neither our partnership agreement nor any other agreement requires Spectra Energy to pursue a business strategy that favors us. Spectra Energy's directors and officers have a fiduciary duty to make these decisions in the best interests of the owners of Spectra Energy, which may be contrary to our interests;
- our general partner is allowed to take into account the interests of parties other than us, such as Spectra Energy and its affiliates, in resolving conflicts of interest;
- Spectra Energy and its affiliates are not limited in their ability to compete with us;
-

our general partner may make a determination to receive a quantity of our Class B units in exchange for resetting the target distribution levels related to its incentive distribution rights without the approval of the Conflicts Committee of our general partner or our unitholders;

- some officers of Spectra Energy who provide services to us also devote significant time to the business of Spectra Energy and will be compensated by Spectra Energy for the services rendered to it;

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- our general partner has limited its liability and reduced its fiduciary duties, and has also restricted the remedies available to our unitholders for actions that, without the limitations, might constitute breaches of fiduciary duty. By purchasing common units, unitholders will be deemed to have consented to some actions and conflicts of interest that might otherwise constitute a breach of fiduciary or other duties under applicable law;
- our general partner determines the amount and timing of asset purchases and sales, borrowings, issuances of additional partnership securities and reserves, each of which can affect the amount of cash that is distributed to unitholders;
- our general partner determines the amount and timing of any capital expenditures and, based on the applicable facts and circumstances, whether a capital expenditure is classified as a maintenance capital expenditure (which reduces operating surplus) or an expansion capital expenditure (which does not reduce operating surplus). This determination can affect the amount of cash that is distributed to our unitholders;
- our general partner determines which costs incurred by it and its affiliates are reimbursable by us;
- in some instances, our general partner may cause us to borrow funds in order to permit the payment of cash distributions, even if the purpose or effect of the borrowing is to make incentive distributions;
- our partnership agreement does not restrict our general partner from causing us to pay it or our affiliates for any services rendered to us or entering into additional contractual arrangements with any of these entities on our behalf;
- our general partner intends to limit its liability regarding our contractual and other obligations and, in some circumstances, is entitled to be indemnified by us;
- our general partner may exercise its limited right to call and purchase common units if it and its affiliates own more than 80% of the common units;
- our general partner controls the enforcement of obligations owed to us by our general partner and its affiliates; and
- our general partner decides whether to retain separate counsel, accountants or others to perform services for us.

Affiliates of our general partner, including Spectra Energy, DCP Midstream and DCP Midstream Partners, LP, are not limited in their ability to compete with us, which could limit commercial activities or our ability to acquire additional assets or businesses.

Neither our partnership agreement nor the omnibus agreement among us, Spectra Energy and others prohibits affiliates of our general partner, including Spectra Energy, DCP Midstream, LLC and DCP Midstream Partners, LP, from owning assets or engaging in businesses that compete directly or indirectly with us. In addition, Spectra Energy and its affiliates may acquire, construct or dispose of additional transmission, storage and gathering or other assets in the future, without any obligation to offer us the opportunity to purchase or construct any of those assets. Each of these entities is a large, established participant in the midstream energy business and each has significantly greater resources and experience than we have, which may make it more difficult for us to compete with these entities with respect to commercial activities as well as for acquisition candidates. As a result, competition from these entities could adversely affect our results of operations and available cash.

If a unitholder is not an Eligible Holder, such unitholder will not be entitled to receive distributions or allocations of income or loss on common units and those common units will be subject to redemption at a price that may be below the current market price.

In order to comply with certain FERC rate-making policies applicable to entities that pass through taxable income to their owners, we have adopted certain requirements regarding those investors who may own our common and subordinated units. Eligible Holders are individuals or entities subject to United States federal income taxation on the income generated by us or entities not subject to United States federal income taxation on the income generated by us, so long as all of the entity’s owners are subject to such taxation. If a unitholder is not a person who fits the requirements to be an Eligible Holder, such unitholder may not receive distributions or allocations of income and loss on the unitholder’s units and the unitholder runs the risk of having the units redeemed by us at the lower of the unitholder’s purchase price cost or the then-current market price. The redemption price will be paid in cash or by delivery of a promissory note, as determined by our general partner.

Cost reimbursements to our general partner and its affiliates for services provided, which will be determined by our general partner, will be substantial and will reduce our distributable cash flow.

Pursuant to an omnibus agreement we entered into with Spectra Energy, our general partner and certain of their affiliates, Spectra Energy will receive reimbursement from us for the payment of operating expenses related to our operations and for the provision of various general and administrative services for our benefit, including costs for rendering administrative staff and support services, and overhead allocated to us. These amounts will be determined by our general partner in its sole discretion. Payments for these services will be substantial and will reduce the amount of distributable cash flow. In addition, under

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Delaware partnership law, our general partner has unlimited liability for our obligations, such as our debts and environmental liabilities, except for contractual obligations that are expressly made without recourse to our general partner. To the extent our general partner incurs obligations on our behalf, we are obligated to reimburse or indemnify it. If we are unable or unwilling to reimburse or indemnify our general partner, our general partner may take actions to cause us to make payments of these obligations and liabilities. Any such payments could reduce the amount of our cash otherwise available for distribution.

Our partnership agreement limits our general partner's fiduciary duties to holders of our common units, and restricts the remedies available to holders of our common units for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty.

Our partnership agreement contains provisions that reduce the fiduciary standards to which our general partner would otherwise be held by state fiduciary duty laws. For example, our partnership agreement:

- permits our general partner to make a number of decisions in its individual capacity, as opposed to in its capacity as our general partner. This entitles our general partner to consider only the interests and factors that it desires, and it has no duty or obligation to give any consideration to any interest of, or factors affecting us, our affiliates or any limited partner;
- provides that our general partner will not have any liability to us or our unitholders for decisions made in its capacity as a general partner so long as it acted in good faith, meaning it believed the decision was in the best interests of our partnership;
- generally provides that affiliated transactions and resolutions of conflicts of interest not approved by the Conflicts Committee of the board of directors of our general partner acting in good faith and not involving a vote of unitholders must be on terms no less favorable to us than those generally being provided to or available from unrelated third parties or must be "fair and reasonable" to us, as determined by our general partner in good faith. In determining whether a transaction or resolution is "fair and reasonable," the general partner may consider the totality of the relationships between the parties involved, including other transactions that may be particularly advantageous or beneficial to unitholders;
- provides that our general partner and its officers and directors will not be liable for monetary damages to us, our limited partners or assignees for any acts or omissions unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that the general partner or those other persons acted in bad faith or engaged in fraud or willful misconduct or, in the case of a criminal matter, acted with knowledge that the conduct was criminal; and
- provides that in resolving conflicts of interest, it will be presumed that in making its decision the general partner or its Conflicts Committee acted in good faith, and in any proceeding brought by or on behalf of any limited partner or us, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption.

Our general partner may elect to cause us to issue Class B units to the general partner in connection with a resetting of the target distribution levels related to the general partner's incentive distribution rights without the approval of the Conflicts Committee of the general partner or holders of our common units and subordinated units. This may result in lower distributions to holders of our common units in certain situations.

Our general partner has the right, at a time when there are no subordinated units outstanding and it has received incentive distributions at the highest level to which it is entitled (48%) for each of the prior four consecutive fiscal quarters, to reset the initial cash target distribution levels at higher levels based on the distribution at the time of the exercise of the reset election. Following a reset election by our general partner, the minimum quarterly distribution amount will be reset to an amount equal to the average cash distribution amount per common unit for the two fiscal quarters immediately preceding the reset election (such amount is referred to as the "reset minimum quarterly distribution") and the target distribution levels will be reset to correspondingly higher levels based on percentage increases above the reset minimum quarterly distribution amount.

In connection with resetting these target distribution levels, our general partner will be entitled to receive a number of Class B units. The Class B units will be entitled to the same cash distributions per unit as our common units and will be convertible into an equal number of common units. The number of Class B units to be issued will be equal to that number of common units whose aggregate quarterly cash distributions equaled the average of the distributions to our general partner on the incentive distribution rights in the prior two quarters. We anticipate that our general partner would exercise this reset right in order to facilitate acquisitions or internal growth projects that would not be sufficiently accretive to cash distributions per common unit without such conversion; however, it is possible that our general partner could exercise this reset election at a time when it is experiencing, or may be expected to experience, declines in the cash distributions it receives related to its incentive distribution rights and may therefore desire to be issued our Class B units, which are entitled to receive cash

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distributions from us on the same priority as our common units, rather than retain the right to receive incentive distributions based on the initial target distribution levels. As a result, a reset election may cause our common unitholders to experience dilution in the amount of cash distributions that they would have otherwise received had we not issued new Class B units to our general partner in connection with resetting the target distribution levels related to our general partner incentive distribution rights.

Holders of our common units have limited voting rights and are not entitled to elect our general partner or its directors, which could reduce the price at which the common units will trade.

Unlike the holders of common stock in a corporation, unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management's decisions regarding our business. Unitholders will not elect our general partner or its board of directors, and will have no right to elect our general partner or board of directors on an annual or other continuing basis. The board of directors of our general partner, including the independent directors, will be chosen entirely by its owners and not by the unitholders. Furthermore, if the unitholders were dissatisfied with the performance of the general partner, they will have little ability to remove the general partner. As a result of these limitations, the price at which the common units will trade could be diminished because of the absence or reduction of a takeover premium in the trading price.

Even if holders of our common units are dissatisfied, they cannot initially remove our general partner without its consent.

The unitholders will be unable initially to remove our general partner without its consent because the general partner and its affiliates own sufficient units to be able to prevent its removal. The vote of the holders of at least 66 2/3% of all outstanding units voting together as a single class is required to remove our general partner. As of January 31, 2015, our general partner and its affiliates own 82% of our aggregate outstanding common units.

Our partnership agreement restricts the voting rights of unitholders owning 20% or more of our common units.

Our partnership agreement restricts unitholders' voting rights by providing that any units held by a person that owns 20% or more of any class of units then outstanding, other than our general partner, its affiliates, their transferees and persons who acquired such units with the prior approval of the board of directors of our general partner, cannot vote on any matter. Our partnership agreement also contains provisions limiting the ability of unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting the unitholders' ability to influence the manner or direction of management.

If we are deemed an "investment company" under the Investment Company Act of 1940, it would adversely affect the price of our common units and could have an adverse effect on our business.

Our assets include 100% ownership interests in various pipelines, as well as 50%, 49.9%, 50%, 33% and 33% equity interests in Gulfstream, SESH, Steckman Ridge, Sand Hills and Southern Hills, respectively. If a sufficient amount of our assets that are comprised of equity investments, other assets acquired in the future, are deemed to be "investment securities" within the meaning of the Investment Company Act of 1940, we would either have to register as an investment company under the Investment Company Act, obtain exemptive relief from the SEC or modify the organizational structure or contract rights to fall outside the definition of an investment company. Although general partner interests are typically not considered "securities" or "investment securities," there is a risk that our 50% general partner interest in Steckman Ridge could be deemed to be an investment security. In that event, it is possible that our ownership of this interest, combined with all of our current equity investments or assets acquired in the future, could result in us being required to register under the Investment Company Act if we were not successful in obtaining exemptive relief or otherwise modifying the organizational structure or applicable contract rights. Registering as an investment company could, among other things, materially limit our ability to engage in transactions with affiliates, including the purchase and sale of certain securities or other property to or from our affiliates, restrict our ability to borrow funds or engage in other transactions involving leverage and require us to add additional directors who are independent of us or our affiliates. The occurrence of some or all of these events would adversely affect the price of the common units and could have an adverse effect on our business.

Control of our general partner may be transferred to a third party without common unitholder consent.

Our general partner may transfer its general partner interest to a third party in a merger or in a sale of all or substantially all of its assets without the consent of the unitholders. Furthermore, our partnership agreement does not restrict the ability of the owners of our general partner or its parent from transferring all or a portion of their respective ownership interest in the general partner or its parent to a third party. The new owners of our general partner or its parent would then be in a position to replace

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the board of directors and officers of its parent with its own choices and thereby influence the decisions taken by the board of directors and officers.

Increases in interest rates could adversely affect our unit price and our ability to issue additional equity to make acquisitions, incur debt or for other purposes.

In recent years, the U.S. credit markets have experienced 50-year record lows in interest rates. Interest rates on future credit facilities and debt offerings could be higher than current levels, causing our financing costs to increase accordingly. As with other yield-oriented securities, our unit price is affected by the level of our cash distributions and implied distribution yield. Therefore, changes in interest rates may affect the yield requirements of investors who invest in our units, and a rising interest rate environment could have an adverse effect on our unit price and the ability to issue additional equity to make acquisitions, to incur debt or for other purposes.

We may issue additional units without our common unitholders' approval, which would dilute our existing common unitholders' ownership interests.

Our partnership agreement does not limit the number of additional limited partner interests that we may issue at any time without the approval of our unitholders. The issuance by us of additional common units or other equity securities of equal or senior rank will have the following effects:

- each unitholder's proportionate ownership interest in us will decrease;
- the amount of distributable cash flow on each unit may decrease;
- the ratio of taxable income to distributions may increase;
- the relative voting strength of each previously outstanding unit may be diminished; and
- the market price of the common units may decline.

Spectra Energy and its affiliates may sell units in the public or private markets, which sales could have an adverse effect on the trading price of the common units.

As of January 31, 2015, Spectra Energy and its affiliates hold an aggregate of 241,618,534 common units. The sale of any of these units in the public or private markets could have an adverse effect on the price of the common units or on any trading market that may develop.

Our general partner has a limited call right that may require our common unitholder to sell the units at an undesirable time or price.

If at any time our general partner and its affiliates own more than 80% of the common units, our general partner will have the right, but not the obligation, which it may assign to any of its affiliates or to us, to acquire all, but not less than all, of the common units held by unaffiliated persons at a price not less than their then-current market price. As a result, our common unitholders may be required to sell their common units at an undesirable time or price and may not receive any return on their investment. A common unitholder may also incur a tax liability upon a sale of their units. As of January 31, 2015, our general partner and its affiliates own approximately 82% of our outstanding common units.

Our common unitholders' liability may not be limited if a court finds that unitholder action constitutes control of our business.

A general partner of a partnership generally has unlimited liability for the obligations of the partnership, except for those contractual obligations of the partnership that are expressly made without recourse to the general partner. We are organized under Delaware law and conduct business in a number of other states. The limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in some of the states in which we do business. Our common unitholders could be liable for any and all of our obligations as if our common unitholders were a general partner if a court or government agency determined that:

- we were conducting business in a state but had not complied with that particular state's partnership statute; or
- our common unitholders' right to act with other unitholders to remove or replace the general partner, to approve some amendments to our partnership agreement or to take other actions under our partnership agreement constitutes "control" of our business.

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Unitholders may have liability to repay distributions that were wrongfully distributed to them.

Under certain circumstances, unitholders may have to repay amounts wrongfully returned or distributed to them. Under Section 17-607 of the Delaware Revised Uniform Limited Partnership Act, we may not make a distribution to the unitholder if the distribution would cause our liabilities to exceed the fair value of our assets. Delaware law provides that for a period of three years from the date of the impermissible distribution, limited partners who received the distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the limited partnership for the distribution amount. Substituted limited partners are liable for the obligations of the assignor to make contributions to the partnership that are known to the substituted limited partner at the time it became a limited partner and for unknown obligations if the liabilities could be determined from the partnership agreement. Liabilities to partners on account of their partnership interest and liabilities that are non-recourse to the partnership are not counted for purposes of determining whether a distribution is permitted.

Tax Risks to Common Unitholders

Our tax treatment depends on our status as a partnership for federal income tax purposes, as well as not being subject to a material amount of entity-level taxation by individual states. If the Internal Revenue Service (IRS) treats us as a corporation or we become subject to a material amount of entity-level taxation for state tax purposes, it would substantially reduce the amount of distributable cash flow.

The anticipated after-tax economic benefit of an investment in our common units depends largely on us being treated as a partnership for federal income tax purposes. We have not requested, and do not plan to request, a ruling from the IRS on this or any other tax matter affecting us.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate, which is currently a maximum of 35% and would likely pay state income tax at varying rates. Distributions would generally be taxed again as corporate distributions, and no income, gains, losses or deductions would flow through to the common unitholders. Because a tax would be imposed upon us as a corporation, our distributable cash flow would be substantially reduced. Therefore, treatment of us as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to a common unitholder, likely causing a substantial reduction in the value of our common units.

Current law may change so as to cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to entity-level taxation. In addition, because of widespread state budget deficits and other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation.

Our partnership agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for federal, state or local income tax purposes, the minimum quarterly distribution amount and the target distribution levels may be adjusted to reflect the effect of that law.

If the tax authorities contest the federal income tax positions we take, it may adversely affect the market for our common units, and the cost of any tax authority contest would reduce our distributable cash flow.

We have not requested a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes or any other matter. The IRS may adopt positions that differ from our conclusions. It may be necessary to resort to administrative or court proceedings to sustain some or all of our counsel’s conclusions or the positions we take. A court may not agree with all of our conclusions or positions we take. Any contest with the IRS may materially and adversely affect the market for our common units and the price at which they trade. In addition, the costs of any contest with the IRS would be borne indirectly by the unitholders and our general partner because the costs would reduce our distributable cash flow.

The unitholder may be required to pay taxes on the unitholder’s share of our income even if the unitholder does not receive any cash distributions.

Because the unitholders are treated as partners to whom we allocate taxable income which could be different in amount than the cash distributed, common unitholders are required to pay any federal income taxes and, in some cases, state and local income taxes on the common unitholder's share of taxable income even if the common unitholders receive no cash distributions from us. The common unitholder may not receive cash distributions from us equal to the unitholder's share of taxable income or even equal to the actual tax liability that results from that income.

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Tax gain or loss on disposition of our common units could be more or less than expected.

If the common unitholder sells its common units, the unitholder will recognize a gain or loss equal to the difference between the amount realized and the common unitholder's tax basis in those common units. Because distributions in excess of the common unitholder's allocable share of our net taxable income decrease the common unitholder's tax basis in the common units, the amount, if any, of such prior excess distributions with respect to the units the unitholder sells will, in effect, become taxable income to the unitholder if the unitholder sells such units at a price greater than the tax basis, even if the price the unitholder receives is less than the original cost. Furthermore, a substantial portion of the amount realized, whether or not representing gain, may be taxed as ordinary income due to potential recapture items, including depreciation recapture. In addition, because the amount realized includes the share of our nonrecourse liabilities, if the common unitholder sells the units, the common unitholder may incur a tax liability in excess of the amount of cash the unitholder receives from the sale.

Tax-exempt entities and foreign persons face unique tax issues from owning common units that may result in adverse tax consequences to them.

Investment in common units by tax-exempt entities, such as individual retirement accounts (IRAs), other retirement plans and non-U.S. persons raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. Distributions to non-U.S. persons will be reduced by withholding taxes at the highest applicable effective tax rate, and non-U.S. persons will be required to file United States federal tax returns and pay tax on their share of our taxable income. If the unitholder is a tax-exempt entity or a foreign person, the unitholder should consult a tax advisor before investing in our common units.

We treat each purchaser of our common units as having the same tax benefits without regard to the actual common units purchased. The IRS may challenge this treatment, which could adversely affect the value of the common units.

Because we cannot match transferors and transferees of common units and because of other reasons, we have adopted depreciation and amortization positions that may not conform to all aspects of existing U.S. Treasury Regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to the common unitholder. It also could affect the timing of these tax benefits or the amount of gain from the sale of our common units and could have a negative effect on the value of our common units or result in audit adjustments to the tax returns.

We have adopted certain valuation methodologies that may result in a shift of income, gain, loss and deduction between the general partner and the unitholders. The IRS may challenge this treatment, which could adversely affect the value of the common units.

When we issue additional units or engage in certain other transactions, we determine the fair market value of our assets and allocate any unrealized gain or loss attributable to our assets to the capital accounts of the unitholders and our general partner. Our methodology may be viewed as understating the value of our assets. In that case, there may be a shift of income, gain, loss and deduction between certain unitholders and the general partner, which may be unfavorable to such unitholders. Moreover, subsequent purchasers of common units may have a greater portion of their Internal Revenue Code Section 743(b) adjustment allocated to our tangible assets and a lesser portion allocated to our intangible assets. The IRS may challenge our valuation methods, or our allocation of the Section 743(b) adjustment attributable to tangible and intangible assets, and allocations of income, gain, loss and deduction between the general partner and certain of the unitholders.

A successful IRS challenge to these methods or allocations could adversely affect the amount of taxable income or loss being allocated to the unitholders. It also could affect the amount of gain from the unitholders' sale of common units and could have a negative effect on the value of the common units or result in audit adjustments to unitholders' tax returns without the benefit of additional deductions.

The sale or exchange of 50% or more of our capital and profits interests during any twelve-month period will result in the termination of the partnership for federal income tax purposes.

We will be considered to have terminated the partnership for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. Our termination would, among other things, result in the closing of the taxable year for all unitholders and could result in a deferral of depreciation deductions allowable in computing our taxable income.

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We prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The IRS may challenge this treatment, which could change the allocation of items of income, gain, loss and deduction among our unitholders.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The use of this proration method may not be permitted under existing Treasury Regulations. Recently, however, the U.S. Treasury Department issued proposed Treasury Regulations that provide a safe harbor pursuant to which publicly traded partnerships may use a similar monthly simplifying convention to allocate tax items among transferor and transferee unitholders. Nonetheless, the proposed regulations do not specifically authorize the use of the proration method we have adopted. If the IRS were to challenge our proration method or new Treasury Regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

A unitholder whose units are loaned to a “short seller” to cover a short sale of units may be considered as having disposed of those units. If so, the unitholder would no longer be treated for tax purposes as a partner with respect to those units during the period of the loan and may recognize gain or loss from the disposition.

Because a unitholder whose units are loaned to a “short seller” to cover a short sale of units may be considered as having disposed of the loaned units, the unitholder may no longer be treated for tax purposes as a partner with respect to those units during the period of the loan to the short seller and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan to the short seller, any of our income, gain, loss or deduction with respect to those units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those units could be fully taxable as ordinary income. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller are urged to modify any applicable brokerage account agreements to prohibit their brokers from borrowing and lending their units.

A common unitholder will likely be subject to state and local taxes and return filing requirements in states where the common unitholder does not live as a result of investing in our common units.

In addition to federal income taxes, a common unitholder will likely be subject to other taxes, including foreign, state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we do business or own property, even if the common unitholder does not live in any of those jurisdictions. The common unitholder will likely be required to file foreign, state and local income tax returns and pay state and local income taxes in some or all of these jurisdictions. Further, the common unitholder may be subject to penalties for failure to comply with those requirements. It is the common unitholder’s responsibility to file all United States federal, foreign, state and local tax returns. Our counsel has not rendered an opinion on the foreign, state or local tax consequences of an investment in the common units.

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Item 1B. Unresolved Staff Comments.

None.

Item 2. Properties.

At December 31, 2014, we had over 100 primary facilities located in the United States and Canada. We generally own sites associated with our major pipeline facilities, such as compressor stations. However, we generally operate our transmission 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 13 of Notes to Consolidated Financial Statements, none of our properties were secured by mortgages or other material security interests at December 31, 2014.

Our principal executive offices are located at 5400 Westheimer Court, Houston, Texas 77056, which is a facility leased by Spectra Energy. We also maintain offices in, among other places, Calgary, Alberta. 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 16 of Notes to Consolidated Financial Statements for discussions of other legal proceedings.

Item 4. Mine Safety Disclosures.

Not applicable.

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PART II

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

Our common units are listed on the NYSE under the symbol "SEP." The following table sets forth the high and low intra-day sales prices for our common units during the periods indicated, as reported by the NYSE, and the amount of the quarterly cash distributions we paid on each of our common units.

Common Unit Data by Quarter

	Distributions Paid in the Quarter per Common Unit	Unit Price Range (a) High	Low
2014			
First Quarter	$ 0.54625	$51.00	$41.53
Second Quarter	0.55625	57.56	48.10
Third Quarter	0.56625	57.69	50.67
Fourth Quarter	0.57625	60.07	47.01
2013			
First Quarter	$ 0.495	$40.08	$31.59
Second Quarter	0.50125	47.23	34.42
Third Quarter	0.50875	47.73	40.00
Fourth Quarter	0.51625	46.75	41.02

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

As of January 31, 2015, there were approximately 39 holders of record of our common units. A cash distribution to unitholders of $0.58875 per limited partner unit was declared on February 4, 2015 and was paid on February 27, 2015, which is a $0.0125 per limited partner unit increase over the cash distribution of $0.57625 per limited partner unit paid on November 26, 2014.

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Unit Performance Graph

The following graph reflects the comparative changes in the value from January 1, 2010 through December 31, 2014 of $100 invested in (1) Spectra Energy Partners’ common units, (2) the Standard & Poor’s 500 Stock Index, and (3) the Alerian MLP Index. The amounts included in the table were calculated assuming the reinvestment of distributions, at the time distributions were paid.

	January 1,	December 31,				
	2010	2010	2011	2012	2013	2014
Spectra Energy Partners	$100.00	$117.03	$120.64	$125.29	$191.51	$251.17
S&P 500 Stock Index	100.00	115.06	117.49	136.30	180.44	205.14
Alerian MLP Index	100.00	135.85	154.70	162.13	206.84	216.78

Distributions of Available Cash

General. Our partnership agreement requires that, within 60 days after the end of each quarter, we distribute all of our Available Cash, as defined in the partnership agreement, to unitholders of record on the applicable record date.

Minimum Quarterly Distribution. The Minimum Quarterly Distribution, as set forth in the partnership agreement, is $0.30 per limited partner unit per quarter, or $1.20 per limited partner unit per year. The quarterly distribution as of February 4, 2015 is $0.58875 per limited partner unit, or $2.355 per limited partner unit annualized. There is no guarantee that this distribution rate will be maintained or that we will pay the Minimum Quarterly Distribution on the units in any quarter. Even if our cash distribution policy is not modified or revoked, the amount of distributions paid under our policy and the decision to make any distribution is determined by our general partner, taking into consideration the terms of the partnership agreement.

General Partner Interest and Incentive Distribution Rights. Our general partner is entitled to 2% of all quarterly distributions since inception. This general partner interest is represented by 6,017,649 general partner units. Our general partner has the right, but not the obligation, to contribute a proportionate amount of capital to us to maintain its current general partner interest. The general partner’s initial 2% interest in these distributions will be reduced if we issue additional units in the future and our general partner does not contribute a proportionate amount of capital to maintain its 2% general partner interest. Our general partner contributed $7 million in 2014, $159 million in 2013 and $4 million in 2012 to maintain its 2% interest.

Our general partner also currently holds incentive distribution rights that entitle it to receive increasing percentages of the cash we distribute from operating surplus in excess of $0.345 per unit per quarter, up to a maximum of 50%. The maximum incentive distribution right of 50% was achieved in 2014, 2013, and 2012. The maximum distribution of 50% includes distributions paid to our general partner on its 2% general partner interest and assumes that our general partner maintains its

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general partner interest at 2%. The maximum distribution of 50% does not include any distributions that our general partner may receive on common units that it owns.

Equity Compensation Plans

For information related to our equity compensation plans, see Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters.

Item 6. Selected Financial Data.

The following selected financial data should be read in conjunction with Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and Item 8. Financial Statements and Supplementary Data. The Express-Platte acquisition and the U.S. Assets Dropdown have been accounted for as acquisitions under common control, resulting in the recast of our prior results. See Note 2 of Notes to Consolidated Financial Statements for further discussion of the transactions.

	2014	2013	2012	2011	2010
	(Unaudited)				
	(in millions, except per-unit amounts)				
Statements of Operations					
Operating revenues	$2,269	$1,965	$1,754	$1,746	$1,678
Operating income	1,136	973	897	880	834
Net income—noncontrolling interests	23	16	15	15	15
Net income—controlling interests (a)	1,004	1,070	580	570	507
Limited Partner Unit Data					
Net income per limited partner unit—basic and diluted (b)	$2.84	$7.15	$5.60	$5.82	$6.04
Distributions paid per limited partner unit	2.245	2.02125	1.93	1.845	1.70

(a) Includes a $354 million benefit related to the elimination of accumulated deferred income tax liabilities in 2013. See Note 6 of Notes to Consolidated Financial Statements for further discussion.

(b) Weighted average limited partners units outstanding used in the calculation of net income per limited partner unit for periods prior to the November 1, 2013 U.S. Assets Dropdown has not been recast. See Note 7 of Notes to Consolidated Financial Statements for further discussion.

	December 31,				
	2014	2013	2012	2011	2010
	(Unaudited)				
	(in millions)				
Balance Sheets					
Total assets	$17,793	$16,794	$13,885	$12,445	$11,837
Long-term debt including capital leases, less current maturities	5,149	5,178	3,105	2,073	2,569
Notes payable—affiliates	—	—	4,185	3,911	3,720

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Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations.

INTRODUCTION

Management’s Discussion and Analysis should be read in conjunction with Item 8. Financial Statements and Supplementary Data.

The Express-Platte acquisition and the U.S. Assets Dropdown have been accounted for as acquisitions under common control, resulting in the recast of our prior results, excluding distributable cash flow. See Note 2 of Notes to Consolidated Financial Statements for further discussion of the transactions.

EXECUTIVE OVERVIEW

We reported net income from controlling interests of $1,004 million in 2014 compared with $1,070 million in 2013. Excluding the income tax benefit in 2013 related to the elimination of deferred income tax liabilities as a result of the U.S. Assets Dropdown, earnings increased mainly due to expansion projects, primarily on Texas Eastern, higher earnings from the continued ramp up of volumes on Sand Hills and Southern Hills and the acquisition of Express-Platte in March 2013. Distributable cash flow was $1,055 million in 2014 compared with $315 million in 2013.

We increased our quarterly cash distribution each quarter in 2014, from $0.54625 per limited partner unit for the fourth quarter of 2013 which was paid in February 2014, to $0.58875 per unit for the fourth quarter of 2014 which was paid on February 27, 2015. We intend to increase our quarterly distribution by at least one and a quarter cents per unit each quarter through 2017. The declaration and payment of distributions is subject to the sole discretion of our Board of Directors and depends upon many factors, including the financial condition, earnings and capital requirements of our operating subsidiaries, covenants associated with certain debt obligations, legal requirements, regulatory constraints, our partnership agreement and other factors deemed relevant by our Board of Directors.

We invested $1.2 billion of capital and investment expenditures in 2014, including $0.9 billion of expansion and investment capital expenditures. We continue to foresee significant expansion capital spending over the next several years, with approximately $2.1 billion planned for 2015. We will rely upon cash flows from operations, including cash distributions received from our equity investments, and various financing transactions, which may include issuances of short-term and long-term debt, to fund our liquidity and capital requirements for 2015. Given that we expect to continue to pursue expansion opportunities over the next several years, capital resources will continue to include long-term borrowings and possibly unit issuances. We expect to maintain an investment-grade capital structure and liquidity profile that supports our strategic objectives. Therefore, we will continue to monitor market requirements and our liquidity, and make adjustments to these plans, as needed.

We are committed to an investment-grade balance sheet and continued prudent financial management of our capital structure. Therefore, financing these growth activities will continue to be based on our strong and growing fee-based earnings
and cash flows as well as the issuances of debt and/or equity securities. As of December 31, 2014, we have access to a $2.0
billion revolving credit facility which is used principally as a back-stop for our commercial paper program.

Our Strategy. Our strategy is to create superior and sustainable value for our investors, customers, employees and communities by delivering natural gas, liquids and crude oil infrastructure to premium markets. We will grow our business through organic growth, greenfield expansions and strategic acquisitions, with a focus on safety, reliability, customer responsiveness and profitability. We intend to accomplish this by:

- Building off the strength of our asset base.
- Maximizing that base through sector leading operations and service.
- Effectively executing the projects we have secured.
- Securing new growth opportunities that add value for our investors within each of our business segments.
- Expanding our value chain participation into complementary infrastructure assets.

Natural gas supply dynamics continue to rapidly change, and there is general recognition that natural gas can be an effective solution for meeting the energy needs of North America and beyond. This causes us to be optimistic about future growth opportunities. Identified opportunities include growth in natural gas-fired generation, growth in industrial markets, LNG exports in North America, growth related to moving new sources of gas supplies to markets and significant new liquids pipeline infrastructure. With our advantage of providing continuous access from leading supply regions through to the last mile

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of pipe in growing natural gas, NGL and crude oil markets, we expect to continue expanding our assets and operations to meet the evolving needs of our customers.

Crude oil supply dynamics also continue to evolve as North American production increases. Growing North American crude oil production is displacing imports from overseas and driving increased demand for crude oil transportation and logistics. Although recent decreases in global crude oil prices may dampen near-term growth in North American oil production, we remain confident about the long-term proposition and our ability to capture future opportunities and grow our crude oil pipeline business.

Successful execution of our strategy will be determined by such key factors as the continued production of, and the consumption of, natural gas, NGLs and crude oil within the United States and Canada, our ability to provide creative solutions for customers' evolving energy needs, maintaining leadership as a safe and reliable operator, and continued successful execution on our capital projects.

We continue to be actively engaged in the national discussions in both the United States and Canada regarding energy policy and have taken a lead role in shaping policy as it relates to pipeline safety and operations.

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

Most of our revenues are based on regulated tariff rates, which include the recovery of certain fuel costs. Lower overall economic output would reduce the volume of natural gas and NGLs transported and gathered and processed at our plants, and the volume of crude oil transported, resulting in lower earnings and cash flows. This decline would primarily affect gathering revenues, potentially 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. Pipeline transportation and storage customers continue to renew most contracts as they expire.

Our combined key natural gas markets—the northeastern and the southeastern United States—are projected to continue to exhibit higher than average annual growth in natural gas demand versus the North American and continental United States average growth rates through 2019. This demand growth is primarily driven by the natural gas-fired electricity generation sector and other new industrial gas demands, including LNG. The natural gas industry is currently experiencing a significant shift in the sources of supply, and this dramatic change is affecting our growth strategies. Traditionally, supply to our markets has come from the Gulf Coast region, both onshore and offshore. The national supply profile is shifting to new sources of gas from natural gas shale basins in the Rockies, Midcontinent, Appalachia, Texas and Louisiana. These supply shifts are shaping the growth strategies that we will pursue, and therefore, will affect the nature of the projects anticipated in the capital and investment expenditure increases discussed below in “Liquidity and Capital Resources.” Recent community and political pressures have arisen around the production processes associated with extracting natural gas from the natural gas shale basins. Although we continue to believe that natural gas will remain a viable energy solution for the U.S., these pressures could increase costs and/or cause a slowdown in the production of natural gas from these basins, and therefore, could negatively affect our growth plans.

Our key crude oil markets include the Rocky Mountain and Midwest states with growing connectivity to the Gulf Coast and West Coast of the United States. Growth in our business is dependent on growing crude oil supply from North American sources and the ability of that supply to displace imported crude oil from overseas. The recent decline in crude oil prices may adversely affect the availability and cost-competitiveness of North American crude oil supply and sustained low oil prices could have a negative impact on our current business and associated growth opportunities.

The shift to and increase in natural gas supply have resulted in declines in the price of natural gas in North America. As a result, there has been a shift to extracting gas in richer, "wet" gas areas, like the Marcellus shale. This has depressed activity in "dry" fields like the Fayetteville shale where our Ozark gathering and transmission assets are located. As the balance of supply and demand evolves, we expect activity in these areas to push prices higher.

However, should the activity in the region continue to decline, our businesses there may be subject to possible impairment. The supply increase has also had a negative impact on the seasonal price spreads historically seen between the summer and winter months. As a result, the value of storage assets and contracts has declined in recent years, negatively impacting the results of our storage facilities. While we expect storage values to stabilize and strengthen in the future, should these market factors continue to keep downward pressure on the seasonality spread and re-contracting, we could be subject to further reduced value and possible impairment of our storage assets.

Our businesses in the United States and Canada are subject to laws and regulations on the federal, state and provincial levels. Regulations applicable to the natural gas transmission, crude oil transportation and storage industries have a significant

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effect on the nature of the businesses and the manner in which they operate. Changes to regulations are ongoing and we cannot predict the future course of changes in the regulatory environment or the ultimate effect that any future changes will have on our businesses.

These laws and regulations can result in increased capital, operating and other costs. Environmental laws and regulations generally require us to obtain and comply with a wide variety of environmental licenses, permits, inspections and other approvals. Compliance with environmental laws and regulations can require significant expenditures, including expenditures for cleanup costs and damages arising out of contaminated properties. In particular, compliance with major Clean Air Act regulatory programs may cause us to incur significant capital expenditures to obtain permits, evaluate offsite impacts of our operations, install pollution control equipment, and otherwise assure compliance.

Our interstate pipeline operations are subject to pipeline laws and safety regulations administered by PHMSA of the U.S. Department of Transportation. These laws and regulations require us to comply with a significant set of requirements for the design, construction, maintenance and operation of our interstate pipelines. In January 2012, the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 was signed into law. This Act amends the Pipeline Safety Act in a number of significant ways, including the assessing of higher penalties for violations.

Many of the changes to the Pipeline Safety Act have been completed, while others are substantially in progress with resolution expected in 2015. Additionally, Congress is tasked with reauthorization of the Pipeline Safety Act during fiscal year 2015. 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 or cash flows.

Additionally, investments and projects located in Canada expose us to risks related to Canadian laws, taxes, economic conditions, fluctuations in currency rates, political conditions and policies of the Canadian government. During the past several years, the Canadian dollar has fluctuated compared to the U.S. dollar, which affected earnings to varying degrees for brief periods. Changes in the exchange rate or any other factors are difficult to predict and may affect our future results.

Our strategic objectives include a critical focus on capital expansion projects that will require access to capital markets. An inability to access capital at competitive rates could affect our ability to implement our strategy. Market disruptions or a downgrade in our credit ratings may increase the cost of borrowings or affect our ability to access one or more sources of liquidity.

During the past few years, capital expansion projects have been exposed to cost pressures associated with the availability of skilled labor, the pricing of materials and challenges associated with ensuring the protection of our environment and continual safety enhancements to our facilities. We maintain a strong focus on project management activities to address these pressures as we move forward with planned expansion opportunities. Significant cost increases could negatively affect the returns ultimately earned on current and future expansions.

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

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RESULTS OF OPERATIONS

	2014	2013	2012
	(in millions)		
Operating revenues	$2,269	$1,965	$1,754
Operating expenses	1,133	992	857
Operating income	1,136	973	897
Equity in earnings of unconsolidated affiliates	133	89	86
Other income and expenses, net	31	59	29
Interest expense	238	383	407
Earnings before income taxes	1,062	738	605
Income tax expense (benefit)	35	(348)	10
Net income	1,027	1,086	595
Net income—noncontrolling interests	23	16	15
Net income—controlling interests	$1,004	$1,070	$580

2014 Compared to 2013

Operating Revenues. The $304 million, or 15%, increase was driven by:

- revenues from expansion projects, primarily on Texas Eastern,
- the acquisition of Express-Platte in March 2013,
- increased natural gas transportation revenues due to new contracts mainly on Texas Eastern and Algonquin,
- higher crude oil transportation revenues for both Express and Platte pipelines mainly as a result of increased tariff rates and higher revenue volumes, and
- higher processing revenues mainly due to volumes, partially offset by
- a decrease in gas storage revenues due to lower rates.

Operating Expenses. The $141 million, or 14%, increase was driven mainly by:

- operating costs from Express-Platte,
- expansion projects, primarily on Texas Eastern,
- higher allocated governance costs associated with the U.S. Assets Dropdown, and
- higher depreciation due to the acquisition of Express-Platte and expansion projects.

Equity in Earnings of Unconsolidated Affiliates. The $44 million increase was mostly attributable to higher earnings due to the continued ramp up of volumes on Sand Hills and Southern Hills.

Other Income and Expenses. The $28 million decrease was mainly attributable to lower allowance for funds used during construction (AFUDC) resulting from decreased capital spending on expansion projects.

Interest Expense. The $145 million decrease was driven mainly by:

- the restructuring of an intercompany loan contributed to us as part of the U.S. Assets Dropdown, partially offset by
- higher debt balances attributable to a $1.9 billion debt issuance in late September 2013, primarily related to the U.S. Assets Dropdown, and
- lower capitalized interest resulting from projects placed in service in 2013.

Income Tax Expense. The $383 million increase was mainly due to the elimination of deferred income tax liabilities as a result of the U.S. Assets Dropdown and resulting changes in tax status of certain entities in 2013.

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2013 Compared to 2012

Operating Revenues. The $211 million, or 12%, increase was mainly driven by:

- the acquisition of Express-Platte in March 2013, and
- higher revenues from expansion projects primarily on Texas Eastern, partially offset by
- lower recoveries of electric power and other costs passed through to customers,
- lower storage revenues, and
- lower processing revenues associated with pipeline operations.

Operating Expenses. The $135 million, or 16%, increase was driven by:

- operating costs from Express-Platte,
- expansion projects primarily on Texas Eastern,
- higher allocated governance costs,
- higher depreciation due to the acquisition of Express-Platte and expansion projects,
- higher employee benefit costs, ad valorem taxes, net of lower software amortization, and
- transaction costs related to the U.S. Assets Dropdown, partially offset by
- lower electric power and other costs passed through to customers.

Other Income and Expenses, Net. The $30 million increase was primarily due to higher AFUDC resulting from increased capital spending on expansion projects.

Income Tax Expense (Benefit). Deferred income tax liabilities were eliminated and recorded as a benefit to Income Tax Expense (Benefit) in connection with the U.S. Assets Dropdown and resulting changes in tax status of certain entities.

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

Segment Results

Management evaluates segment performance based on EBITDA transactions. Cash, cash equivalents and investments are managed centrally, so the gains and losses on foreign currency remeasurement, and interest and dividend income, are excluded from the segments' EBITDA. We consider segment EBITDA to be a good indicator of each segment's operating performance from its continuing operations, as it represents the results of our operations without regard to financing methods or capital structures. Our segment EBITDA may not be comparable to similarly titled measures of other companies because other companies may not calculate EBITDA in the same manner.

Our U.S. Transmission business primarily provides transmission and storage of natural gas for customers in various regions of the northeastern and southeastern United States. Our Liquids business primarily provides transportation of crude oil and NGLs for customers in central and southern United States and Canada.

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Segment EBITDA is summarized in the following table. Detailed discussions follow.

EBITDA by Business Segment

	2014	2013	2012
	(in millions)		
U.S. Transmission	$1,415	$1,279	$1,251
Liquids	240	132	—
Total reportable segment EBITDA	1,655	1,411	1,251
Other	(64)	(27)	(9)
Total reportable segment and other EBITDA	1,591	1,384	1,242
Depreciation and amortization	288	262	231
Interest expense	238	383	407
Interest income and other	(3)	(1)	1
Earnings before income taxes	$1,062	$738	$605

The amounts discussed below are after eliminating intercompany transactions.

U.S. Transmission

	2014	2013	Increase (Decrease)	2012	Increase (Decrease)
	(in millions)				
Operating revenues	$1,939	$1,727	$212	$1,754	$(27)
Operating expenses					
Operating, maintenance and other	647	594	53	617	(23)
Other income and expenses	123	146	(23)	114	32
EBITDA	$1,415	$1,279	$136	$1,251	$28

2014 Compared to 2013

Operating Revenues. The $212 million increase was driven by:

- a $168 million increase due to expansion projects, primarily on Texas Eastern,
- a $44 million increase due to higher natural gas transportation revenues due to new contracts mainly on Texas Eastern and Algonquin,
- a $19 million increase due to higher processing revenues mainly due to volumes, and
- a $7 million increase in recoveries of electric power and other costs passed through to customers, partially offset by
- a $25 million decrease in gas storage revenues due to lower rates.

Operating Expenses. The $53 million increase was driven by:

- a $33 million increase from expansion projects, primarily on Texas Eastern,
- a $10 million increase in operating costs mostly due to repairs and maintenance,
- a $7 million increase in recoveries of electric power and other costs passed through to customers, and
- a $3 million increase from project development costs expensed in 2014.

Other Income and Expenses. The $23 million decrease was primarily due to lower AFUDC resulting from decreased capital spending on expansion projects.

EBITDA. The $136 million increase was driven by expansions, primarily on Texas Eastern, higher natural gas transportation revenues from new contracts and higher processing revenues, partially offset by lower storage revenues due to lower rates.

2013 Compared to 2012

Operating Revenues. The $27 million decrease was driven by:

- a $42 million decrease in recoveries of electric power and other costs passed through to customers,
- a $24 million decrease due to lower storage revenues as a result of lower contract renewal rates, and
- an $8 million decrease from lower processing revenues associated with pipeline operations, partially offset by
- a $48 million increase from expansion projects primarily on Texas Eastern.

Operating Expenses. The $23 million decrease was driven by:

- a $42 million decrease in electric power and other costs passed through to customers, partially offset by
- a $10 million increase due to higher employee benefit costs and ad valorem taxes, net of lower software amortization, and
- a $6 million increase from expansion projects primarily on Texas Eastern.

Other Income and Expenses. The $32 million increase was primarily due to higher AFUDC resulting from increased capital spending on expansion projects.

EBITDA. The $28 million increase was driven by higher earnings from the expansions at Texas Eastern, partially offset by lower storage revenues, higher operating costs, and lower processing revenues.

Matters Affecting Future U.S. Transmission Results

We plan to continue earnings growth through capital efficient projects, such as transportation and storage expansion to support a two-pronged “supply push” / “market pull” strategy, as well as continued focus on optimizing the performance of the existing operations through organizational efficiencies and cost control. “Supply push” is when producers agree to pay to transport specified volumes of natural gas in order to support the construction of new pipelines or the expansion of existing pipelines. “Market pull” is taking gas away from established liquid supply points and building pipeline transportation capacity to satisfy end-user demand in new markets or demand growth in existing markets. Future earnings growth will be dependent on the success of our expansion plans in both the market and supply areas of the pipeline network, which includes, among other things, shale gas exploration and development areas, the ability to continue renewing service contracts and continued regulatory stability. Natural gas storage prices have recently been challenged as a result of increasing natural gas supply and narrower seasonal price spreads. Gas supply and demand dynamics continue to change as a result of the development of new non-conventional shale gas supplies. The increase in natural gas supply has resulted in declines in the price of natural gas in North America. As a result, there has been a shift to extracting gas in richer, "wet" gas areas, like the Marcellus shale. This has depressed activity in "dry" fields like the Fayetteville shale where our Ozark gathering and transmission assets are located. As the balance of supply and demand evolves, we expect activity in these areas to push prices higher. However, should the activity in the region continue to decline, our businesses there may be subject to possible impairment.

The supply increase has also had a negative impact on the seasonal price spreads historically seen between the summer and winter months. The value of storage assets and contracts has declined in recent years, negatively affecting the results of our storage facilities. While we expect storage values to stabilize and strengthen in the future, should these market factors continue to keep downward pressure on the seasonality spread and re-contracting, we could be subject to further reduced value and possible impairment of our storage assets.

Our interstate pipeline operations are subject to pipeline safety regulations administered by PHMSA of the U.S. Department of Transportation. These laws and regulations require us to comply with a significant set of requirements for the design, construction, maintenance and operation of our interstate pipelines. In January 2012, the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 was signed into law. This Act amends the Pipeline Safety Act in a number of significant ways, including the assessing of higher penalties for violations.

Many of the changes to the Pipeline Safety Act, such as increasing penalties, have been completed, while others are substantially in progress with resolution expected in 2015. Additionally, Congress is tasked with reauthorization of the Pipeline Safety Act during fiscal year 2015. 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 a reduction of allowable operating pressures as authorized by

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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 or cash flows.

Liquids

	2014	2013	Increase (Decrease)	2012	Increase (Decrease)
	(in millions)				
Operating revenues	$330	$238	$92	$—	$238
Operating expenses					
Operating, maintenance and other	134	109	25	—	109
Other income and expenses	44	3	41	—	3
EBITDA	$240	$132	$108	$—	$132
Express pipeline revenue receipts, MBbl/d (a,b)	223	219	4	N/A	N/A
Platte PADD II deliveries, MBbl/d (b)	170	168	2	N/A	N/A

(a) Thousand barrels per day.

(b) Data includes activity since March 14, 2013, the date of the acquisition of Express-Platte by Spectra Energy.

Our Liquids segment is comprised of Express-Platte and our investments in Sand Hills and Southern Hills. Results presented herein include Express-Platte since March 14, 2013, the date of Spectra Energy's acquisition, and Sand Hills and Southern Hills since November 15, 2012, the date of Spectra Energy’s acquisition of both entities.

2014 Compared to 2013

Operating Revenues. The $92 million increase in operating revenues was driven by:

- a $68 million increase primarily due to the acquisition of Express-Platte, and
- a $26 million increase in crude oil transportation revenues for both Express and Platte pipelines as a result of increased tariff rates and higher revenue volumes.

Operating Expenses. The $25 million increase in operating expenses was attributable mainly to the acquisition of Express-Platte.

Other Income and Expenses. The $41 million increase was primarily due to higher earnings from the continued ramp up of volumes on Sand Hills and Southern Hills.

EBITDA. The $108 million increase was driven by the acquisition of Express-Platte and higher earnings due to Sand Hills and Southern Hills.

2013 Compared to 2012

Operating Revenues. The $238 million increase was attributable to Express-Platte.

Operating Expenses. The $109 million increase was attributable to Express-Platte.

Other Income and Expenses. The $3 million increase was attributable to our equity earnings in Sand Hills and Southern Hills.

EBITDA. The $132 million increase was primarily driven by the earnings from Express-Platte.

Matters Affecting Future Liquids Results

We plan to continue earnings growth by maximizing throughput on all sections of the pipeline systems. On the Express-Platte system, this entails connecting, where possible, to rail or barge terminals to extend the market reach of the pipeline to refinery-customers beyond the end of the pipeline. This also includes optimizing pipeline and storage operations and expanding terminal operations where appropriate. On the Southern Hills and Sand Hills NGL pipelines, volumes will continue to increase as NGL supply increases behind the system and new extraction plants are connected to the pipeline. Extensions may be added to the lines and pumps may be added to increase capacity.

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Future earnings growth will be dependent on the success in renewing existing contracts or in securing new supply and market for all pipelines. This will require ongoing increases in supply of both crude oil and NGL and continued access to attractive markets. For the NGL pipelines, continued growth is dependent on successful execution of expansion projects to attach new supply.

See Matters Affecting Future U.S. Transmission Results for discussions of the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 and PHMSA, which are also applicable to the Liquids segment.

Other

	2014	2013	Increase (Decrease)	2012	Increase (Decrease)
	(in millions)				
Operating expenses	$64	$27	$37	$9	$18
EBITDA	$(64)	$(27)	$(37)	$(9)	$(18)

2014 Compared to 2013

Operating Expenses. The $37 million increase was driven by higher allocated governance costs, partially offset by transaction costs related to the U.S. Assets Dropdown, which was effective on November 1, 2013.

2013 Compared to 2012

Operating Expenses. The $18 million increase was driven by higher allocated governance costs and transaction costs related to the U.S. Assets Dropdown, which was effective on November 1, 2013.

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Distributable Cash Flow

We define Distributable Cash Flow as EBITDA plus

- distributions from equity investments,
- other non-cash items affecting net income, less
- equity in earnings of unconsolidated affiliates,
- interest expense,
- equity AFUDC,
- net cash paid for income taxes,
- distributions to noncontrolling interests, and
- maintenance capital expenditures, excluding the effect of reimbursable projects.

Distributable Cash Flow does not reflect changes in working capital balances. Distributable Cash Flow should not be viewed as indicative of the actual amount of cash that we plan to distribute for a given period.

Distributable Cash Flow is the primary financial measure used by our management and by external users of our financial statements to assess the amount of cash that is available for distribution. The effects of the U.S. Assets Dropdown and the Express-Platte acquisition have been excluded from the Distributable Cash Flow calculation for periods prior to the dropdown transactions in order to reflect the true amount of the cash that was available for distribution.

Distributable Cash Flow is a non-GAAP measure and should not be considered an alternative to Net Income, Operating Income, cash from operations or any other measure of financial performance or liquidity presented in accordance with generally accepted accounting principles (GAAP) in the United States. Distributable Cash Flow excludes some, but not all, items that affect Net Income and Operating Income and these measures may vary among other companies. Therefore, Distributable Cash Flow as presented may not be comparable to similarly titled measures of other companies.

Significant drivers of variances in Distributable Cash Flow between the periods presented are substantially the same as those previously discussed under Results of Operations. Other drivers include the timing of certain cash outflows, such as capital expenditures for maintenance.

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Reconciliation of Net Income to Non-GAAP "Distributable Cash Flow"

	2014	2013	2012
	(in millions)		
Net Income	$1,027	$1,086	$595
Add:			
Interest expense	238	383	407
Income tax expense (benefit) (a)	35	(348)	10
Depreciation and amortization	288	262	231
Foreign currency loss	3	2	—
Less:			
Interest income	—	1	1
EBITDA	1,591	1,384	1,242
Add:			
Equity in earnings of unconsolidated affiliates	(133)	(89)	(86)
Distributions from equity investments (b)	165	117	105
Other	8	8	9
Less:			
Interest expense	238	383	407
Equity AFUDC	33	58	27
Net cash paid for income taxes	6	—	1
Distributions to noncontrolling interests	29	19	18
Maintenance capital expenditures (c)	270	228	241
Adjustment (d)	—	417	347
Distributable Cash Flow	$1,055	$315	$229

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(a) Tax benefit in 2013 is due to the elimination of deferred income tax liabilities related to the U.S. Assets Dropdown.
(b) Excludes $129 million in distributions from equity investments (SESH $99 million, Sand Hills $21 million, and Southern Hills $9 million) for the 2014 period.
Excludes $63 million in distributions from equity investments (Sand Hills $37 million, and Southern Hills $26 million) for the 2013 period.
(c) Excludes reimbursable expenditures.
(d) Removes the results of the U.S. Assets Dropdown for the periods prior to the dropdown (January 1, 2012 to October 31, 2013) and the results of Express-Platte for the periods prior to the dropdown (March 14, 2013 to August 1, 2013).

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

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

We base our estimates and judgments on historical experience and on other assumptions that we believe are reasonable at the time of application. These estimates and judgments may change as time passes and more information becomes available. If estimates are different than the actual amounts recorded, adjustments are made in subsequent periods to take into consideration the new information. We discuss our critical accounting policies and estimates and other significant accounting policies with our Audit Committee.

Regulatory Accounting

We account for certain of our operations under accounting for regulated entities. As a result, we record assets and liabilities that result from the regulated ratemaking process that may not be recorded under GAAP for non-regulated entities. Regulatory assets generally represent incurred costs that have been deferred because such costs are probable of future recovery in customer rates. Regulatory liabilities generally represent obligations to make refunds to customers or for instances where the regulator provides current rates that are intended to recover costs that are expected to be incurred in the future. We continually assess whether the regulatory assets are probable of future recovery by considering factors such as applicable regulatory changes and recent rate orders to other regulated entities. Based on this assessment, we believe our existing regulatory assets are probable of recovery. This assessment reflects the current political and regulatory climate at the state and federal levels, and is subject to change in the future. If future recovery of costs ceases to be probable, regulatory asset write-offs would be required to be recognized. Additionally, regulatory agencies can provide flexibility in the manner and timing of the depreciation of property, plant and equipment and amortization of regulatory assets. Total regulatory assets were $290 million as of December 31, 2014 and $254 million as of December 31, 2013. Total regulatory liabilities were $29 million as of December 31, 2014 and $66 million as of December 31, 2013.

Impairment of Goodwill

We had goodwill balances of $3,244 million at December 31, 2014 and $3,215 million at December 31, 2013. The increase in goodwill in 2014 was the result of an adjustment related to the acquisition of Express-Platte, partially offset by foreign currency translation. See Note 9 of Notes to Consolidated Financial Statements for further discussion.

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

In connection with our quantitative assessments, we primarily use a discounted cash flow analysis to determine fair values of those reporting units. The long-term growth rates used for the reporting units that we quantitatively assess reflect continued expansion of our assets, driven by new natural gas supplies such as shale gas in North America and increasing demand for natural gas transmission capacity on our pipeline systems primarily as a result of forecasted growth in natural gas-fired power plants and increasing demand for crude oil and NGL transportation capacity on our pipeline systems.

We performed a qualitative assessment for all of our reporting units to determine whether it is more likely than not that the respective fair values of these reporting units are less than their carrying amounts, including goodwill as of April 1, 2014 (our annual testing date). Based on that assessment, we determined that this condition, for all reporting units, does not exist. As such, performing the first step of the two-step impairment test for these units was unnecessary. No triggering events occurred during the period from April 1, 2014 through December 31, 2014 that warranted re-testing for goodwill impairment.

Revenue Recognition

Revenues from the transmission, storage and gathering of natural gas, and from the transportation of crude oil are recognized when the service is provided. Revenues related to these services provided but not yet billed are estimated each month. These estimates are generally based on contract data, regulatory information, and preliminary throughput and allocation measurements. Final bills for the current month are billed and collected in the following month. Differences between actual and estimated unbilled revenues are immaterial.

LIQUIDITY AND CAPITAL RESOURCES

Known Trends and Uncertainties

As of December 31, 2014, we had negative working capital of $927 million. This balance includes commercial paper liabilities totaling $907 million and current maturities of long-term debt of $36 million. We will rely upon cash flows from operations, including cash distributions received from our equity affiliates, and various financing transactions, which may include debt and/or equity issuances, to fund our liquidity and capital requirements for 2015. We have access to a revolving credit facility, with available capacity of $1.1 billion at December 31, 2014. This facility is used principally as a back-stop for our commercial paper program, which is used to manage working capital requirements and for temporary funding of capital expenditures. We expect to be self-funding and plan to continue to pursue expansion opportunities over the next several years. Capital resources may continue to include commercial paper, short-term borrowings under our current credit facility and possibly securing additional sources of capital including debt and/or equity.

Cash flows from operations are fairly stable given that substantially all of our revenues and those of our equity affiliates are derived from operations under firm contracts. However, total operating cash flows are subject to a number of factors, including, but not limited to, contract renewal rates and cash distributions from our equity affiliates. The amount of cash distributed to us by our equity affiliates and the amount of cash we may be required to fund, is determined by our equity affiliates based on their operating cash flows and other factors as determined by their management. While we participate on the management committees of these equity affiliates, determination of the amount of distributions and contributions, if any, are not within our control. We received total distributions from equity affiliates of $294 million in 2014, $180 million in 2013 and $106 million in 2012. See Item 1A. Risk Factors for discussion of other factors that could affect our cash flows.

As a result of our ongoing strong earnings performance expected in existing operations, we expect to maintain a capital structure and liquidity profile that supports our strategic objectives. We will continue to monitor market requirements and our liquidity and make adjustments to these plans, as needed.

Cash Flow Analysis

The following table summarizes the changes in cash flows for each of the periods presented:

	Years Ended December 31,		
	2014	2013	2012
	(in millions)		
Net cash provided by (used in):			
Operating activities	$1,333	$1,029	$891
Investing activities	(1,077)	(3,689)	(1,880)
Financing activities	(237)	2,733	1,016
Net increase in cash and cash equivalents	19	73	27
Cash and cash equivalents at beginning of the period	121	48	21
Cash and cash equivalents at end of the period	$140	$121	$48

Operating Cash Flows

Net cash provided by operating activities increased $304 million to $1,333 million in 2014 compared to 2013. This increase was driven primarily by:

- higher earnings in 2014 after adjusting for non-cash items primarily consisting of a $381 million change in deferred income taxes, partially offset by
- changes in working capital.

Net cash provided by operating activities increased $138 million to $1,029 million in 2013 compared to 2012. This increase was primarily due to earnings related to the acquisition of Express-Platte in 2013.

Investing Cash Flows

Net cash flows used in investing activities decreased $2,612 million to $1,077 million in 2014 compared to 2013. This decrease was driven mainly by:

- a $2,210 million net cash outlay for the U.S. Assets Dropdown in 2013,
- a $343 million net cash outlay for the acquisition of Express-Platte in 2013,
- an $80 million increase in distributions received from unconsolidated affiliates in 2014, comprised mostly of a $99 million distribution from SESH with proceeds from a SESH debt offering,
- a $71 million loan to an unconsolidated affiliate in 2013, and
- a $58 million decrease in capital and investment expenditures in 2014. Capital and investment expenditures in 2014 included a $94 million investment in SESH, used by SESH to retire debt, partially offset by
- $141 million of net proceeds from available-for-sale securities in 2013.

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Net cash flows used in investing activities increased $1,809 million to $3,689 million in 2013 compared to 2012. This increase was driven mainly by:

- a $2,234 million increase in acquisitions in 2013, partially offset by
- a $144 million decrease in capital and investment expenditures in 2013, and
- $141 million of net proceeds from available-for-sale securities in 2013 compared to $141 million of net purchases in 2012.

Capital and Investment Expenditures by Business Segment

	Years Ended December 31,		
	2014	2013	2012
	(in millions)		
U.S. Transmission (a,b)	$1,160	$1,000	$930
Liquids (c)	81	299	513
Total consolidated	$1,241	$1,299	$1,443

(a) Excludes the $2,210 million net cash outlay for the U.S. Assets Dropdown in 2013 and the $319 million acquisition of M&N U.S. in 2012.

(b) Excludes a $71 million loan to an unconsolidated affiliate in 2013.

(c) Excludes the $343 million net cash outlay for the acquisition of Express-Platte in 2013.

Capital and investment expenditures for 2014 totaled $1,241 million and included $888 million for expansion projects, $259 million for maintenance and other projects and a $94 million investment in SESH. SESH used the funds, along with its funds received from its other partners, to retire maturing debt.

We project 2015 capital and investment expenditures of approximately $2.4 billion, including $2.1 billion of expansion capital expenditures and $0.3 billion for maintenance and upgrades of existing plants, pipelines and infrastructure to serve growth. Given our objective of growth through acquisitions, we anticipate that we will continue to invest significant amounts of capital to acquire assets. Expansion capital expenditures may vary significantly based on investment opportunities.

On November 3, 2014, we completed the second of the three planned transactions related to the U.S. Assets Dropdown. This transaction consisted of acquiring an additional 24.95% ownership interest in SESH and the remaining 1% ownership interest in Steckman Ridge. Total consideration was approximately 4.3 million newly issued common units and 86,000 general partner units to Spectra Energy. See Note 2 of Notes to Consolidated Financial Statements for further discussion.

In November 2013, we completed the closing of substantially all of the U.S. Assets Dropdown, including Spectra Energy's remaining 60% interest in the U.S. portion of Express-Platte. We paid Spectra Energy aggregate consideration with the issuance of approximately 171.1 million newly issued partnership units and $2.3 billion in cash. See Note 2 of Notes to Consolidated Financial Statements for further discussion.

In August 2013, we acquired a 40% ownership interest in Express US and a 100% ownership interest in Express Canada from subsidiaries of Spectra Energy for $410 million in cash and 7.2 million of newly issued common and general partner units. See Note 2 of Notes to Consolidated Financial Statements for further discussion.

In 2012, we acquired a 39% ownership interest in M&N U.S. from Spectra Energy for approximately $319 million in cash and approximately $56 million in newly issued common and general partner units. See Note 2 of Notes to Consolidated Financial Statements for further discussion.

Capital expansion projects are developed and executed using results-proven project management processes. We evaluate the strategic fit and commercial and execution risks, and continuously measure performance compared to plan. Ongoing communications between project teams and senior leadership ensure we maintain the right focus and deliver the expected results. We expect that significant natural gas infrastructure, including both natural gas transportation and storage with links to growing gas supplies and markets, will be needed over time to serve growth in gas-fired power generation, oil-to-gas conversions, industrial development and attachments to new gas supply.

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Expansion capital expenditures included several key projects placed into service in 2014, including:

- Buffalo Terminal Expansion—Buffalo expansion consists of two additional 150,000 bbl above ground storage tanks along with delivery pump and piping facilities to supply crude oil to the Cenex Harvest States Front Range pipeline. This project was placed in-service during the third quarter of 2014.
- TEAM 2014—A 600 MMcf/d expansion of the Texas Eastern pipeline system consisting of new pipeline construction. The project is designed to transport gas produced in the Marcellus Shale to U.S. markets in the Northeast, Midwest and Gulf Coast. This project was placed in-service during the fourth quarter of 2014.
- Bobcat Storage Expansion—The project as a whole is designed to expand the storage capacity and capabilities of the Bobcat facility. Cavern Well 4 increases the working gas capacity by 9.9 Bcf, and was placed in-service during the fourth quarter of 2014.
- Kingsport—An additional 61 MMcf/d on the East Tennessee system to support a customer's multi-year project to convert five coal-fired power plant boilers to natural gas. The project was placed in-service during the fourth quarter of 2014.

Significant 2015 expansion projects expenditures are expected to include:

- OPEN—A 550 MMcf/d expansion of the Texas Eastern pipeline system consisting of new pipeline, a new compressor station and other associated facility upgrades. The project is designed to transport gas produced in the Utica Shale and Marcellus Shale to U.S. markets in the Midwest, Southeast and Gulf Coast. In-service is scheduled by the fourth quarter of 2015.
- AIM—A 342 MMcf/d expansion of the Algonquin system consisting of replacement pipeline, new pipeline, new and modified meter station facilities and additional compression at existing stations. The project is designed to transport gas from existing interconnects in New Jersey and New York to LDC marked in the northeast. In-service is scheduled by the fourth quarter of 2016.
- Gulf Market Expansion—This Texas Eastern system expansion project connects growth markets (Gulf Coast LNG and industrials) with diverse, growing shale supply. The project consists of installing up to seven compressor stations to provide up to 650 MMcf/d. The project will be executed in two phases. Phase 1, due to go in-service in the fourth quarter of 2016, will provide north to south compression at five stations. Phase 2, due to go in-service in the fourth quarter of 2017, will provide north to south compression at two stations.
- Sabal Trail—A 1,100 MMcf/d of new capacity to access onshore shale gas supplies. Facilities include a new 465-mile pipeline, laterals and various compressor stations. In-service is scheduled by the second quarter of 2017.
- Salem Lateral—An expansion of the Algonquin system for delivery of 115 MMcf/d of natural gas to the Footprint Salem Harbor Power Station in Salem, Massachusetts. In-service is scheduled by the first quarter of 2016.
- Uniontown to Gas City—The project will provide shippers with 425 MMcf/d of firm transportation service from the supply-rich area west of Uniontown, Pennsylvania to a new delivery meter with Panhandle Eastern Pipe Line near Gas City, Indiana for further redelivery to markets in the Midwest. These five shippers combine to contract for the full 425 MMcf/d of capacity under the project. In-service is scheduled by the fourth quarter of 2015.
- DCP Sand Hills - Red Lake—The project includes the construction of two lateral pipelines with a combined length of 170 miles to connect a DCP gas processing plant and two third-party gas processing plants to the Sand Hills Pipeline. The project extends the reach of the Sand Hills Pipeline into a fast growing region of the Permian basin and enhances long-term throughput on the pipeline. It is expected to be in-service in the second half of 2015.
- Ozark Conversion—The project includes abandonment of portions of the Ozark Gas Transmission system from natural gas service and leasing of the abandoned lines to Magellan to transport approximately 75,000 barrels per day of refined products. In-service is scheduled by the third quarter of 2015.

Financing Cash Flows

Net cash used in financing activities totaled $237 million in 2014 compared to $2,733 million provided by financing activities in 2013. This $2,970 million change was driven mainly by:

- a $549 million increase in distributions to partners in 2014,
- a $523 million contribution from parent in 2013, and
- $441 million of net redemptions of long-term debt in 2014 compared to $2,241 million of net issuances in 2013, which were mostly used to fund the U.S. Assets Dropdown, partially offset by
- a $567 million net increase in commercial paper issuances in 2014 compared to 2013,
- a $122 million increase in contributions from noncontrolling interest in 2014, and
- a $117 million increase in proceeds from issuances of units in connection with our at-the-market program in 2014.

Net cash provided by financing activities increased $1,717 million to $2,733 million in 2013 compared to 2012. This change was driven mainly by:

- a $1,682 million net increase in long-term debt issuances in 2013 compared to 2012, mostly to fund the U.S. Assets Dropdown from Spectra Energy,
- $523 million of net contributions from parent in 2013 compared to $240 million of net contributions in 2012, and
- a $69 million increase in proceeds from issuance of units in 2013, partially offset by
- a $307 million net decrease in issuances of commercial paper in 2013 compared to 2012.

Significant Financing Activities—2014

Common Unit Issuances. On November 3, 2014, we issued 4.3 million common units and 86,000 general partner units to Spectra Energy in connection with the U.S. Assets Dropdown, valued at $186 million. See Note 2 of Notes to Consolidated Financial Statements for further discussion of this transaction.

In November 2013, we entered into an equity distribution agreement under which we may sell and issue common units up to an aggregate amount of $400 million. This at-the-market offering program allows us to offer and sell common units at prices deemed appropriate through a sales agent. Sales of common units, if any, will be made by means of ordinary brokers' transactions on the NYSE, in block transactions, or as otherwise agreed to between the sales agent and us.

We issued 6.4 million common units to the public in 2014 under our at-the-market program and 132,000 general partner units to Spectra Energy. Total net proceeds were $334 million, including $7 million of proceeds from Spectra Energy. The net proceeds were used for general partnership purposes, which may have included debt repayments, future acquisitions, capital expenditures and/or additions to working capital. In 2015 through the date of this report, we have issued 184,000 common units to the public and 4,000 general partner units to Spectra Energy, for total net proceeds of $10 million, including $0.2 million of proceeds from Spectra Energy, under this program.

Significant Financing Activities—2013

Debt Issuances. The following long-term debt issuances were completed during 2013 to fund a portion of the cash consideration for the U.S. Assets Dropdown from Spectra Energy which closed in November 2013:

	Amount (in millions)	Interest Rate	Due Date
Spectra Energy Partners, LP	$1,000	4.75 %	2024
Spectra Energy Partners, LP	500	2.95 %	2018
Spectra Energy Partners, LP	400	5.95 %	2043
Spectra Energy Partners, LP	400	variable	2018

Common Unit Issuances. In November 2013, we issued 167.6 million common units and 3.4 million general partner units to Spectra Energy in connection with the U.S. Assets Dropdown, valued at $7.4 billion. See Note 2 of Notes to Consolidated Financial Statements for further discussion of the U.S. Assets Dropdown.

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We issued 0.6 million common units to the public in 2013 under our at-the-market program, for total net proceeds of $24 million.
In August 2013, we issued 7.1 million common units and 0.1 million general partner units to Spectra Energy in connection with the acquisition of Express-Platte, valued at $319 million. See Note 2 of Notes to Consolidated Financial Statements for further discussion of the acquisition of Express-Platte.
In April 2013, we issued 5.2 million common units to the public and 0.1 million general partner units. Total net proceeds were $193 million. The net proceeds from this issuance were temporarily invested in restricted available-for-sale securities until the Express-Platte dropdown, at which time the funds were partially used to pay for a portion of the transaction. See Note 2 of Notes to Consolidated Financial Statements for a discussion of the Express-Platte transaction.
Significant Financing Activities—2012
Debt Issuances. The following long-term debt issuances were completed during 2012:

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

Common Unit Issuance. In 2012, we issued 5.5 million common units to the public and 0.1 million general partner units to Spectra Energy. Total net proceeds were $148 million and were restricted for the purpose of funding capital expenditures and acquisitions.
Available Credit Facility and Restrictive Debt Covenants

	Expiration Date	Total Credit Facility Capacity	Commercial Paper Outstanding at December 31, 2014	Available Credit Facility Capacity
		(in millions)		
Spectra Energy Partners, LP	2019	$2,000	$907	$1,093

On December 11, 2014, we amended our credit agreement. The expiration date was extended one year expiring in December 2019.
The issuances of commercial paper, letters of credit and revolving borrowings reduce the amount available under the credit facility. As of December 31, 2014, there were no letters of credit issued or revolving borrowings outstanding under the credit facility.
The credit agreements contain various covenants, including the maintenance of consolidated leverage ratio, as defined in the agreements. Failure to meet those covenants beyond applicable grace periods could result in accelerated due dates and/or termination of the agreements. As of December 31, 2014, we were in compliance with those covenants. In addition, the credit agreements allow for acceleration of payments or termination of the agreements due to nonpayment, or in some cases, due to the acceleration of other significant indebtedness of us or of some of our subsidiaries. Our credit agreements do not contain provisions that trigger an acceleration of indebtedness based solely on the occurrence of a material adverse change in our financial condition or results of operations.
As noted above, the terms of the credit agreements require us to maintain a ratio of total Consolidated Indebtedness-to- Consolidated EBITDA, as defined in the agreements, of 5.0 to 1 or less. As of December 31, 2014 this ratio was 3.7 to 1.
Term Loan Agreement. In November 2013, we entered into and borrowed $400 million under a senior unsecured five-year term loan agreement. A portion of the proceeds from the borrowing was used to pay Spectra Energy for the U.S. Assets Dropdown.

Cash Distributions. The partnership agreement requires that, within 60 days after the end of each quarter, we distribute all of our Available Cash, as defined, to unitholders of record on the applicable record date.

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We increased the quarterly cash distributions each quarter of 2014 from $0.54625 per limited partner unit for the fourth quarter of 2013 to $0.58875 per limited partner unit for the fourth quarter of 2014. The cash distribution for the fourth quarter of 2014 was declared on February 4, 2015 and was paid on February 27, 2015.

Our Board of Directors evaluates each individual quarterly distribution decision based on an assessment of growth in cash available to make distributions. Growth in our cash available to make distributions over time is dependent on incremental organic growth expansion, third-party acquisitions or acquisitions from Spectra Energy. Our amount of Available Cash depends primarily upon our cash flows, including cash flow from financial reserves and working capital or other borrowings, and not solely on profitability, which will be affected by non-cash items. As a result, we may make cash distributions during periods when we record a net loss for financial accounting purposes and may not make cash distributions during periods when we record net earnings for financial accounting purposes.

Other Financing Matters. We have an effective shelf registration statement on file with the SEC to register the issuance of unspecified amounts of limited partner common units and various debt securities and another registration statement on file with the SEC to register the issuance of $500 million, in the aggregate, of limited partner common units and various debt securities over time. This registration statement has $143 million available as of December 31, 2014.

In January 2015, we filed a registration statement with the SEC to register an additional $500 million of common units. This shelf registration became effective on February 2, 2015.

Off Balance Sheet Arrangements

We do not have any off-balance sheet financing entities or structures, except for normal operating lease arrangements and financings entered into by equity investments. These debt obligations do not contain provisions requiring accelerated payment of the related obligation in the event of specified declines in credit ratings.

Contractual Obligations

We enter into contracts that require payment of cash at certain periods based on certain specified minimum quantities and prices. The following table summarizes our contractual cash obligations for each of the periods presented. The table below excludes all amounts classified as Total Current Liabilities on the December 31, 2014 Consolidated Balance Sheet other than Current Maturities of Long-Term Debt. It is expected that the majority of Total Current Liabilities will be paid in cash in 2015.

Contractual Obligations as of December 31, 2014

	Payments Due by Period				
	Total	2015	2016 & 2017	2018 & 2019	2020 & Beyond
	(in millions)				
Long-term debt (a)	$7,478	$249	$1,108	$1,247	$4,874
Operating leases (b)	173	15	35	28	95
Purchase obligations (c)	2,531	118	434	147	1,832
Total contractual cash obligations	$10,182	$382	$1,577	$1,422	$6,801

(a) See Note 13 of Notes to Consolidated Financial Statements. Amounts include principal payments and estimated scheduled interest payments over the life of the associated debt.
(b) See Note 16 of Notes to Consolidated Financial Statements.
(c) Purchase obligations reflected in the Consolidated Balance Sheets have been excluded from the above table.

Quantitative and Qualitative Disclosures About Market Risk

We are exposed to market risks associated with interest rates and credit exposure. We have established comprehensive risk management policies to monitor and manage these market risks. Spectra Energy is responsible for the overall governance of managing our interest rate risk and credit risk, including monitoring exposure limits.

Credit Risk

Credit risk represents the loss that we would incur if a counterparty fails to perform under its contractual obligations. Our exposure generally relates to receivables and unbilled revenue for services provided, as well as volumes owed by customers for imbalances or gas loaned by us generally under park and loan services and no-notice services. Our principal customers for natural gas transmission, storage and gathering services are industrial end-users, marketers, exploration and production companies, LDCs and utilities located throughout the United States. Customers on the Express-Platte system are primarily refineries located in the Rocky Mountain and Midwestern states of the United States. Other customers include oil producers and marketing entities. We have concentrations of receivables from these industry sectors. These concentrations of customers may affect our overall credit risk in that risk factors can negatively affect the credit quality of the entire sector.

Where exposed to credit risk, we analyze the customers' financial condition prior to entering into an agreement, establish credit limits and monitor the appropriateness of those limits on an ongoing basis. We also obtain parental guarantees, cash deposits or letters of credit from customers to provide credit support, where appropriate, based on our financial analysis of the customer and the regulatory or contractual terms and conditions applicable to each contract. A significant amount of our credit exposures for transmission, storage and gathering services are with customers who have an investment-grade rating (or the equivalent based on an evaluation by Spectra Energy), or are secured by collateral. However, we cannot predict to what extent our business would be impacted by deteriorating conditions in the economy, including possible declines in our customers' creditworthiness. As a result of future capital projects for which natural gas producers may be the primary customer, our credit exposure with below investment-grade customers may increase.

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

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

Interest Rate Risk

We are exposed to risk resulting from changes in interest rates as a result of our issuance of variable and fixed-rate debt and commercial paper. We manage our interest rate exposure by limiting our variable-rate exposures to percentages of total debt and by monitoring the effects of market changes in interest rates. We also enter into financial derivative instruments, including, but not limited to, interest rate swaps to manage and mitigate interest rate risk exposure. See also Notes 1, 14 and 15 of Notes to Consolidated Financial Statements.

As of December 31, 2014, we had interest rate hedges in place for various purposes. We are party to "pay floating—receive fixed" interest rate swaps with a total notional amount of $300 million to hedge against changes in the fair value of our fixed-rate debt that arise as a result of changes in market interest rates. These swaps also allow us to transform a portion of the underlying interest payments related to our long-term fixed-rate debt securities into variable-rate interest payments in order to achieve our desired mix of fixed and variable-rate debt.

Based on a sensitivity analysis as of December 31, 2014, it was estimated that if short-term interest rates average 100 basis points higher (lower) in 2015 than in 2014, interest expense, net of offsetting interest income, would fluctuate by $15 million. Comparatively, based on a sensitivity analysis as of December 31, 2013, had short-term interest rates averaged 100 basis points higher (lower) in 2014 than in 2013, it was estimated that interest expense, net of offsetting interest income, would have fluctuated by approximately $6 million. These amounts were estimated by considering the effect of the hypothetical interest rates on variable-rate debt outstanding, adjusted for interest rate hedges, short-term investments, and cash and cash equivalents outstanding as of December 31, 2014 and 2013.

OTHER ISSUES

For information on other issues, see Notes 5 and 16 of Notes to Consolidated Financial Statements.

New Accounting Pronouncements

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

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

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

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Item 8. Financial Statements and Supplementary Data.

Management's Annual Report on Internal Control over Financial Reporting

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

The management of our General Partner, including our Chief Executive Officer and Chief Financial Officer, has conducted an evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2014 based on the criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on that evaluation, management concluded that our internal control over financial reporting was effective at the reasonable assurance level as of December 31, 2014. Deloitte & Touche LLP, our independent registered public accounting firm, has audited and issued a report on the effectiveness of our internal control over financial reporting. Their report is included herein.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of Spectra Energy Partners GP, LLC and Unitholders of Spectra Energy Partners, LP:
Houston, Texas

We have audited the accompanying consolidated balance sheets of Spectra Energy Partners, LP and subsidiaries (the "Partnership") as of December 31, 2014 and 2013, and the related consolidated statements of operations, comprehensive income, cash flows and equity for each of the three years in the period ended December 31, 2014. Our audits also included the financial statement schedule listed in the index at Item 15. We also have audited the Partnership's internal control over financial reporting as of December 31, 2014, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Partnership's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Annual Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on these financial statements and financial statement schedule and an opinion on the Partnership's internal control over financial reporting based on our audits.

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

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

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Spectra Energy Partners, LP and subsidiaries as of December 31, 2014 and 2013, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2014, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein. Also, in our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2014, based on the criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
February 27, 2015

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SPECTRA ENERGY PARTNERS, LP
CONSOLIDATED STATEMENTS OF OPERATIONS
(In millions, except per-unit amounts)

	Years Ended December 31, 2014	2013		2012	
Operating Revenues					
Transportation of natural gas	$1,685	$1,470		$1,465	
Transportation of crude oil	302	224		—	
Storage of natural gas and other	282	271		289	
Total operating revenues	2,269	1,965		1,754	
Operating Expenses					
Operating, maintenance and other	690	603		521	
Depreciation and amortization	288	262		231	
Property and other taxes	155	127		105	
Total operating expenses	1,133	992		857	
Operating Income	1,136	973		897	
Other Income and Expenses					
Equity in earnings of unconsolidated affiliates	133	89		86	
Other income and expenses, net	31	59		29	
Total other income and expenses	164	148		115	
Interest Expense	238	383		407	
Earnings Before Income Taxes	1,062	738		605	
Income Tax Expense (Benefit)	35	(348	) (a)	10	
Net Income	1,027	1,086		595	
Net Income—Noncontrolling Interests	23	16		15	
Net Income—Controlling Interests	$1,004	$1,070		$580	
Calculation of Limited Partners' Interest in Net Income:					
Net income—Controlling Interests	$1,004	$1,070		$580	
Less: General partner's interest in net income	187	83		37	
Limited partners' interest in net income	$817	$987		$543	
Weighted average limited partners units outstanding — basic and diluted	288	138	(b)	97	(b)
Net income per limited partner unit — basic and diluted	$2.84	$7.15	(b)	$5.60	(b)
Distributions paid per limited partner unit	$2.245	$2.02125		$1.93	

(a) Includes a $354 million benefit related to the elimination of accumulated deferred income tax liabilities. See Note 6 for further discussion.

(b) Weighted average limited partners units outstanding used in the calculation of net income per limited partner unit for periods prior to the November 1, 2013 U.S. Assets Dropdown has not been recast. See Note 7 for further discussion.

See Notes to Consolidated Financial Statements.

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SPECTRA ENERGY PARTNERS, LP
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(In millions)

	Years Ended December 31,		
	2014	2013	2012
Net Income	$1,027	$1,086	$595
Other comprehensive loss:			
Foreign currency translation adjustments	(14)	(7)	—
Reclassification of cash flow hedges into earnings	(1)	(1)	(1)
Total other comprehensive loss	(15)	(8)	(1)
Total Comprehensive Income	1,012	1,078	594
Less: Comprehensive Income—Noncontrolling Interests	23	16	15
Comprehensive Income—Controlling Interests	$989	$1,062	$579

See Notes to Consolidated Financial Statements.

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SPECTRA ENERGY PARTNERS, LP
CONSOLIDATED BALANCE SHEETS
(In millions)

	December 31, 2014	2013
ASSETS		
Current Assets		
Cash and cash equivalents	$140	$121
Receivables (net of allowance for doubtful accounts of $3 and $1 at December 31, 2014 and 2013, respectively)	306	355
Inventory	42	42
Fuel tracker	44	28
Other	23	19
Total current assets	555	565
Investments and Other Assets		
Investments in and loans to unconsolidated affiliates	1,589	1,396
Goodwill	3,244	3,215
Other	8	2
Total investments and other assets	4,841	4,613
Property, Plant and Equipment		
Cost	15,594	14,592
Less accumulated depreciation and amortization	3,459	3,229
Net property, plant and equipment	12,135	11,363
Regulatory Assets and Deferred Debits	262	253
Total Assets	$17,793	$16,794

See Notes to Consolidated Financial Statements.

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SPECTRA ENERGY PARTNERS, LP
CONSOLIDATED BALANCE SHEETS
(In millions)

	December 31, 2014	2013
LIABILITIES AND EQUITY		
Current Liabilities		
Accounts payable	$246	$231
Commercial paper	907	338
Taxes accrued	63	44
Interest accrued	60	61
Current maturities of long-term debt	36	445
Other	170	216
Total current liabilities	1,482	1,335
Long-term Debt	5,149	5,178
Deferred Credits and Other Liabilities		
Deferred income taxes	37	34
Regulatory and other	119	106
Total deferred credits and other liabilities	156	140
Commitments and Contingencies		
Equity		
Partners' Capital		
Common units (294.7 million and 284.1 million units issued and outstanding at December 31, 2014 and 2013, respectively)	10,474	9,778
General partner units (6.0 million and 5.8 million units outstanding at December 31, 2014 and 2013, respectively)	284	241
Accumulated other comprehensive income	(20)	(5)
Total partners' capital	10,738	10,014
Noncontrolling interests	268	127
Total equity	11,006	10,141
Total Liabilities and Equity	$17,793	$16,794

See Notes to Consolidated Financial Statements.

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SPECTRA ENERGY PARTNERS, LP
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In millions)

	Years Ended December 31,		
	2014	2013	2012
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$1,027	$1,086	$595
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	296	266	240
Deferred income tax expense (benefit)	27	(354)	6
Equity in earnings of unconsolidated affiliates	(133)	(89)	(86)
Distributions received from unconsolidated affiliates	131	97	90
Decrease (increase) in:			
Receivables	(18)	(11)	11
Other current assets	(5)	(73)	3
Increase (decrease) in:			
Accounts payable	6	96	15
Taxes accrued	19	6	3
Other current liabilities	(7)	50	28
Other, assets	(26)	(61)	(25)
Other, liabilities	16	16	11
Net cash provided by operating activities	1,333	1,029	891
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures	(1,081)	(1,019)	(930)
Investments in and loans to unconsolidated affiliates	(160)	(280)	(513)
Acquisitions, net of cash acquired	—	(2,553)	(319)
Distributions received from unconsolidated affiliates	163	83	16
Purchases of held-to-maturity securities	(43)	(51)	—
Proceeds from sales and maturities of held-to-maturity securities	43	55	—
Purchases of available-for-sale securities	—	(5,865)	(630)
Proceeds from sales and maturities of available-for-sale securities	—	6,006	489
Loan to unconsolidated affiliate	—	(71)	—
Other	1	6	7
Net cash used in investing activities	(1,077)	(3,689)	(1,880)
CASH FLOWS FROM FINANCING ACTIVITIES			
Proceeds from issuance of long-term debt	—	2,287	1,049
Payments for the redemption of long-term debt	(441)	(46)	(490)
Net increase in commercial paper	569	2	309
Proceeds from notes payable—affiliates	—	17	31
Payments on notes payable—affiliates	—	—	(34)
Distributions to noncontrolling interests	(29)	(19)	(18)
Contributions from noncontrolling interests	145	23	—
Proceeds from issuance of units	334	217	148
Distributions to partners	(815)	(266)	(214)
Contribution from parent	—	523	240
Other	—	(5)	(5)

Net cash provided by (used in) financing activities	(237)	2,733	1,016
Net increase in cash and cash equivalents	19	73	27
Cash and cash equivalents at beginning of the period	121	48	21
Cash and cash equivalents at end of the period	$140	$121	$48
Supplemental Disclosures			
Cash paid for interest, net of amount capitalized	$232	$348	$391
Cash paid for income taxes	6	—	1
Property, plant and equipment noncash accruals	94	74	28
Units issued as partial consideration for acquisitions	186	7,751	56

See Notes to Consolidated Financial Statements.

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SPECTRA ENERGY PARTNERS, LP
CONSOLIDATED STATEMENTS OF EQUITY
(In millions)

	Partners' Capital				
	Common	General Partner	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
December 31, 2011	$5,311	$120	$4	$110	$5,545
Net income	543	37	—	15	595
Other comprehensive loss	—	—	(1)	—	(1)
Net transfer to parent	(385)	(8)	—	—	(393)
Attributed deferred tax benefit	—	15	—	—	15
Issuance of units	201	4	—	—	205
Distributions to partners	(187)	(27)	—	—	(214)
Distributions to noncontrolling interests	—	—	—	(18)	(18)
December 31, 2012	5,483	141	3	107	5,734
Net income	987	83	—	16	1,086
Other comprehensive loss	—	—	(8)	—	(8)
Purchase price under net acquired assets in Express-Platte acquisition	20	—	—	—	20
Excess purchase price over net acquired assets in U.S. Assets Dropdown	(70)	(1)	—	—	(71)
Net transfer to parent	(4,224)	(133)	—	—	(4,357)
Attributed deferred tax benefit	—	33	—	—	33
Issuance of units	7,810	159	—	—	7,969
Distributions to partners	(225)	(41)	—	—	(266)
Contributions from noncontrolling interests	—	—	—	23	23
Distributions to noncontrolling interests	—	—	—	(19)	(19)
Other, net	(3)	—	—	—	(3)
December 31, 2013	9,778	241	(5)	127	10,141
Net income	817	187	—	23	1,027
Other comprehensive loss	—	—	(15)	—	(15)
Purchase price under net acquired assets in Express-Platte acquisition	10	—	—	—	10
Excess purchase price over net acquired assets in U.S. Assets Dropdown	(10)	—	—	—	(10)
Net transfer from parent	16	—	—	—	16
Attributed deferred tax benefit	—	16	—	2	18
Issuance of units	509	11	—	—	520
Distributions to partners	(644)	(171)	—	—	(815)
Contributions from noncontrolling interests	—	—	—	145	145
Distributions to noncontrolling interests	—	—	—	(29)	(29)

Other, net	(2)	—	—	—	(2)
December 31, 2014	$10,474	$284	$(20)	$268	$11,006

See Notes to Consolidated Financial Statements.

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SPECTRA ENERGY PARTNERS, LP
Notes to Consolidated Financial Statements
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1. Summary of Operations and Significant Accounting Policies

The terms “we,” “our,” “us” and “Spectra Energy Partners” as used in this report refer collectively to Spectra Energy Partners, LP 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 Partners.

Nature of Operations. Spectra Energy Partners, through its subsidiaries and equity affiliates, is engaged in the transmission, storage and gathering of natural gas, the transportation and storage of crude oil, and the transportation of natural gas liquids (NGLs) through interstate pipeline systems. We are a Delaware master limited partnership (MLP). As of December 31, 2014, Spectra Energy Corp (Spectra Energy) and its subsidiaries collectively owned 82% of us and the remaining 18% was publicly owned.

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

On August 2, 2013, we acquired a 40% ownership interest in the U.S. portion of the Express-Platte crude oil pipeline system (Express US) and a 100% ownership interest in the Canadian portion of the pipeline system (Express Canada)(collectively, Express-Platte) from subsidiaries of Spectra Energy (the Express-Platte acquisition). On November 1, 2013, we acquired substantially all of Spectra Energy's U.S. transmission, storage and liquid assets, including Spectra Energy's remaining 60% interest in Express US (the U.S. Assets Dropdown).

On November, 3 2014, we completed the second of the three planned transactions related to the U.S. Assets Dropdown. This transaction consisted of acquiring an additional 24.95% ownership interest in Southeast Supply Header, LLC (SESH) and an additional 1% interest in Steckman Ridge, LP (Steckman Ridge) from Spectra Energy. The remaining and final transaction, related to the U.S. Assets Dropdown is expected to occur in November 2015, and will consist of Spectra Energy's remaining 0.1% interest in SESH.

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The Express-Platte acquisition and the U.S. Assets Dropdown have been accounted for as acquisitions under common control, resulting in the recast of our prior results. See Note 2 for further discussion of the transactions.

Our costs of doing business have been reflected in our financial accounting records for the periods presented. These costs include direct charges and allocations from Spectra Energy and its affiliates for business services, such as payroll, accounts payable and facilities management; corporate services, such as finance and accounting, legal, human resources, investor relations, public and regulatory policy, and senior executives; and pension and other post-retirement benefit costs.

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

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

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

Foreign Currency Translation. The Canadian dollar has been determined to be the functional currency of Express Canada based on an assessment of the economic circumstances of those operations. Assets and liabilities of Express Canada are translated into U.S. dollars at current exchange rates. Translation adjustments resulting from fluctuations in exchange rates are included as a separate component of Other Comprehensive Loss on the Consolidated Statements of Comprehensive Income. Revenue and expense accounts of these operations are translated at average monthly exchange rates prevailing during the periods. Gains and losses arising from transactions denominated in currencies other than the functional currency are included in the results of operations of the period in which they occur. Foreign currency transaction losses totaled $3 million and $2 million in 2014 and 2013, respectively and are included in Other Income and Expenses, Net on the Consolidated Statements of Operations. There were no foreign currency transaction losses in 2012.

Revenue Recognition. Revenues from the transmission, storage and gathering of natural gas, and from the transportation of crude oil are generally recognized when the service is provided. Revenues related to these services provided but not yet billed are estimated each month. These estimates are generally based on contract data, regulatory information and preliminary throughput and allocation measurements. Final bills for the current month are billed and collected in the following month. Differences between actual and estimated unbilled revenues are immaterial. There were no customers accounting for 10% or more of consolidated revenues during 2014 or 2013. National Grid plc accounted for 10% of consolidated revenues in 2012. We also have certain customer contracts with billed amounts that decline annually over the terms of the contracts. Differences between the amounts billed and recognized are deferred on the Consolidated Balance Sheets.

Allowance for Funds Used During Construction (AFUDC). AFUDC, which represents the estimated debt and equity costs of capital funds necessary to finance the construction of certain new regulated facilities, consists of two components, an equity component and an interest expense component. The equity component is a non-cash item. After construction is completed, we are permitted to recover these costs through inclusion in the rate base and in the depreciation provision. AFUDC is capitalized as a component of Property, Plant and Equipment - Cost in the Consolidated Balance Sheets, with offsetting credits to the Consolidated Statements of Operations through Other Income and Expenses, Net for the equity component and Interest Expense for the interest expense component. The total amount of AFUDC included in the Consolidated Statements of Operations was $42 million in 2014 (an equity component of $33 million and an interest expense component of $9 million), $96 million in 2013 (an equity component of $58 million and an interest expense component of $38 million) and $46 million in 2012 (an equity component of $27 million and an interest expense component of $19 million).

Income Taxes. As a result of our MLP structure, we are not subject to federal income tax. Our federal taxable income or loss is reported on the respective income tax returns of our partners. However, we are subject to Canadian foreign income tax and Tennessee and New Hampshire income tax. Spectra Energy Partners is liable to Spectra Energy for Texas income (margin) tax under a tax sharing agreement. As of December 31, 2014, the difference between the tax basis and the reported amounts of Spectra Energy Partners' assets and liabilities is $12.5 billion.

We are subject to cost-based regulation and consequently record a regulatory tax asset in connection with the tax gross up of AFUDC equity. The corresponding deferred tax liability is recognized as an Attributed Deferred Income Tax Benefit in the Consolidated Statements of Equity since we are a pass-through entity.

Cash and Cash Equivalents. Highly liquid investments with original maturities of three months or less at the date of acquisition, except for the investments that were pledged as collateral against long-term debt as discussed in Note 13 and any investments that are considered restricted funds, are considered cash equivalents.

Inventory. Inventory consists of natural gas retained from shippers for fuel and also includes materials and supplies. Natural gas is recorded at the lower of cost or market. Materials and supplies are recorded at cost, using the average cost method.

Natural Gas Imbalances. The Consolidated Balance Sheets include in-kind balances as a result of differences in gas volumes received and delivered for customers. Since settlement of certain imbalances is in-kind, changes in the balances do not have an effect on our Consolidated Statements of Operations or Consolidated Statements of Cash Flows. Receivables include $68 million and $147 million as of December 31, 2014 and December 31, 2013, respectively, and Other Current Liabilities include $59 million and $116 million as of December 31, 2014 and December 31, 2013, respectively, related to all gas imbalances. Most natural gas volumes owed to or by us are valued at natural gas market index prices as of the balance sheet dates.

Cash Flow and Fair Value Hedges. We have entered into Interest rate swaps which were designated as either a hedge of a forecasted transaction (cash flow hedge) or a hedge of a recognized asset, liability or firm commitment (fair value hedge). For all hedge contracts, we prepare documentation of the hedge in accordance with accounting standards and assess whether the hedge contract is highly effective using regression analysis, both at inception and on a quarterly basis, in offsetting changes in cash flows or fair values of hedged items.

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

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

Investments. We may actively invest a portion of our available cash and restricted funds balances in various financial instruments, including taxable or tax-exempt debt securities. In addition, we invest in short-term money market securities, some of which are restricted due to debt collateral requirements. Investments in available-for-sale (AFS) securities are carried at fair value and investments in held-to-maturity (HTM) securities are carried at cost. Investments in money market securities are also accounted for at fair value. Realized gains and losses, and dividend and interest income related to these securities, including any amortization of discounts or premiums arising at acquisition, are included in earnings. The costs of securities sold are determined using the specific identification method. Purchases and sales of AFS and HTM securities are presented on a gross basis within Cash Flows From Investing Activities in the accompanying Consolidated Statements of Cash Flows. See also Notes 10 and 14 for additional information.

Goodwill. We perform our goodwill impairment test annually and evaluate goodwill when events or changes in circumstances indicate that its carrying value may not be recoverable. No impairments of goodwill were recorded in 2014, 2013 or 2012. See Note 9 for further discussion.

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

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

In connection with our quantitative assessments, we primarily use a discounted cash flow analysis to determine the fair values of those reporting units. Key assumptions in the determination of fair value included the use of an appropriate discount rate and estimated future cash flows. In estimating cash flows, we incorporate expected long-term growth rates in key markets served by our operations, regulatory stability, the ability to renew contracts, commodity prices (where appropriate) and foreign currency exchange rates, as well as other factors that affect our reporting units' revenue, expense and capital expenditure projections. If the carrying amount of the reporting unit exceeds its fair value, a comparison of the fair value and carrying value of the goodwill of that reporting unit needs to be performed. If the carrying value of the goodwill of a reporting unit exceeds the implied fair value of that goodwill, an impairment loss is recognized in an amount equal to the excess. Additional impairment tests are performed between the annual reviews if events or changes in circumstances make it more likely than not that the fair value of a reporting unit is below its carrying amount.

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

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

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

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

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

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

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

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

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

Consolidated Statements of Cash Flows. Cash received from insurance proceeds are classified depending on the activity that resulted in the insurance proceeds. For example, business interruption insurance proceeds are included as a component of operating activities while insurance proceeds from damaged property are included as a component of investing activities. With respect to cash overdrafts, book overdrafts are included within operating cash flows while bank overdrafts, if any, are included within financing cash flows.

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

New Accounting Pronouncements. There were no significant accounting pronouncements adopted in 2014, 2013, and 2012 that had a material impact on our consolidated results of operations, financial position or cash flows. The following new Accounting Standard Updates (ASUs) were issued but not adopted as of December 31, 2014:

ASU No. 2014-08. In April 2014, the Financial Accounting Standards Board (FASB) issued ASU No. 2014-08, “Presentation of Financial Statements (Topic 205) and Property, Plant, and Equipment (Topic 360): Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity.” This ASU revises the definition of discontinued operations by limiting discontinued operations reporting to disposals of components of an entity that represent strategic shifts that have or will have a major effect on an entity’s operations and financial results, removing the lack of continuing involvement criteria and requiring discontinued operations reporting for the disposal of an equity method investment that meets the definition of discontinued operations. The update also requires expanded disclosures for discontinued operations, and disclosure of pretax profit or loss of certain individually significant components of an entity that do not qualify for discontinued operations reporting. This ASU was effective for us on January 1, 2015 and had no impact on our consolidated results of operations, financial position or cash flows.

ASU No. 2014-09. In May 2014, the FASB issued Accounting Standards Update (ASU) No. 2014-09, “Revenue from Contracts with Customers,” which supersedes the revenue recognition requirements of “Revenue Recognition (Topic 605),” and clarifies the principles of recognizing revenue. This ASU is effective for us January 1, 2017. We are currently evaluating this ASU and its potential impact on us.

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2. Acquisitions

U.S. Assets Dropdown. In November 2013, we completed the closing of substantially all of the U.S. Assets Dropdown, excluding a 25.05% ownership interest in SESH and a 1% ownership interest in Steckman Ridge. Consideration to Spectra Energy for the November 2013 closing included $2.3 billion in cash, assumption (indirectly by acquisition of the contributed entities) of approximately $2.4 billion of third-party indebtedness of the contributed entities, 167.6 million newly issued limited partner units and 3.4 million newly issued general partner units.

On November 3, 2014, we completed the second of the three planned transactions related to the U.S. Assets Dropdown. This transaction consisted of acquiring an additional 24.95% ownership interest in SESH and the remaining 1% ownership interest in Steckman Ridge from Spectra Energy. Total consideration was approximately 4.3 million newly issued common units. Also, in connection with this transaction, we issued approximately 86,000 general partner units to Spectra Energy in exchange for the same amount of common units in order to maintain Spectra Energy's 2% general partner interest.

The remaining and final transaction, related to the U.S. Assets Dropdown is expected to occur in November 2015, and will consist of Spectra Energy's remaining 0.1% interest in SESH.

The contributed assets provide transportation and storage of natural gas, crude oil and NGLs for customers in various regions of the U.S. and in Alberta, Canada. The contributed assets included in the U.S. Assets Dropdown, once the third closing is completed, will have consisted of:

- a 100% ownership interest in Texas Eastern Transmission, LP (Texas Eastern)
- a 100% ownership interest in Algonquin Gas Transmission, LLC (Algonquin)
- Spectra Energy’s remaining 60% ownership interest in Express US
- Spectra Energy’s remaining 38.77% ownership interest in Maritimes & Northeast Pipeline, L.L.C. (M&N U.S.)
- a 33.3% ownership interest in DCP Sand Hills Pipeline, LLC (Sand Hills)
- a 33.3% ownership interest in DCP Southern Hills Pipeline, LLC (Southern Hills)
- Spectra Energy’s remaining 1% ownership interest in Gulfstream Natural Gas System, LLC (Gulfstream)
- a 50% ownership interest in SESH
- a 100% ownership interest in Bobcat Gas Storage (Bobcat)
- Spectra Energy’s remaining 50% of Market Hub Partners Holding (Market Hub)
- a 50% ownership interest in Steckman Ridge
- Texas Eastern’s and Express-Platte’s storage facilities

The U.S. Assets Dropdown has been accounted for as an acquisition under common control, resulting in the recast of our prior results. As such, summarized financial information has not been presented.

Express-Platte. In August 2013, we acquired a 40% ownership interest in Express US and a 100% ownership interest in Express Canada from subsidiaries of Spectra Energy for $410 million in cash and 7.2 million of newly issued common and general partner units (valued at $319 million). The Express-Platte pipeline system, which begins in Hardisty, Alberta, and terminates in Wood River, Illinois, is comprised of both the Express and Platte crude oil pipelines. The Express pipeline carries crude oil to U.S. refining markets in the Rockies area, 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.

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The following table summarizes the fair values of the assets and liabilities as of the acquisition date of Express-Platte from third-parties by Spectra Energy.

	Purchase Price Allocation (in millions)
Cash	$67
Receivables	25
Other current assets	9
Goodwill	523
Property, plant and equipment	1,251
Accounts payable	(18)
Other current liabilities	(17)
Deferred credits and other liabilities	(259)
Long-term debt, including current portion	(260)
Total assets acquired/liabilities assumed	$1,321

The allocation of the fair values of assets and liabilities acquired related to the acquisition of Express-Platte was finalized in the first quarter of 2014, resulting in the following adjustments to amounts reported as of December 31, 2013: a $60 million decrease in Property, Plant and Equipment, a $24 million decrease in Deferred Credits and Other Liabilities, and a $1 million decrease in Other Current Assets, resulting in a $37 million increase in Goodwill.

In the first quarter of 2014, we recorded $23 million of income tax expense due to the adjustment to deferred income tax liabilities (eliminated and recorded as an income tax benefit in 2013 in connection with the U.S. Assets Dropdown and resulting changes in tax status of certain entities) as a result of the final purchase price allocation adjustments.

The following table presents unaudited pro forma results of operations information that reflect the acquisition of Express-Platte as if the acquisition had occurred as of January 1, 2012, adjusted for items that are directly attributable to the acquisition. This information has been compiled from current and historical financial statements, and is not necessarily indicative of the results that actually would have been achieved had the transaction occurred at the beginning of the periods presented or that may be achieved in the future.

	Years ended December 31,	
	2013	2012
	(in millions, except per-unit amounts)	
Operating revenues	$2,024	$2,022
Earnings before income taxes	751	707
Net income	1,099	697
Net income-controlling interests	1,083	682
Net income per limited partner unit—basic and diluted	7.01	6.15

M&N U.S. In 2012, we acquired a 38.76% ownership interest in M&N U.S. from Spectra Energy for approximately $319 million in cash and approximately $56 million in newly issued common and general partner units. M&N U.S.' pipeline location and key interconnects with our transmission system link regional natural gas supplies primarily to the northeast U.S. market. M&N U.S. is a part of the U.S. Transmission segment. We acquired Spectra Energy's remaining 38.77% ownership interest in M&N U.S. in connection with the U.S. Assets Dropdown.

The initial 38.76% interest in M&N U.S. was recorded at the historical book value of Spectra Energy of $199 million. The $176 million excess purchase price over the book value of net assets acquired was recorded as a reduction to Partners' Capital, and the $56 million of common and general partner units issued to Spectra Energy were recorded as increases to Partners' Capital.

Sand Hills and Southern Hills. In 2012, Spectra Energy acquired direct one-third ownership interests in Sand Hills and Southern Hills from DCP Midstream, LLC (DCP Midstream), a 50%-owned equity affiliate of Spectra Energy. On November 1, 2013, Spectra Energy contributed its ownership in Sand Hills and Southern Hills to us in the U.S. Asset Dropdown. DCP

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Midstream Partners, LP, DCP Midstream's master limited partnership, and Phillips 66 also each own a direct one-third interest in each of the two pipelines. The Sand Hills pipeline provides NGL transportation from the Permian Basin and Eagle Ford basins to the premium NGL markets on the Gulf Coast. The Southern Hills pipeline provides NGL transportation from the Midcontinent to Mont Belvieu, Texas. Our investments in Sand Hills and Southern Hills are included in Investments in and Loans to Unconsolidated Affiliates on our Consolidated Balance Sheets and Statements of Cash Flows.

3. Transactions with Affiliates

In the normal course of business, we provide natural gas transmission, storage and other services to Spectra Energy and its affiliates.

In addition, pursuant to an agreement with Spectra Energy, Spectra Energy and its affiliates perform centralized corporate functions for us, including legal, accounting, compliance, treasury and other areas. We reimburse Spectra Energy for the expenses to provide these services as well as other expenses it incurs on our behalf, such as salaries of personnel performing services for our benefit and the cost of employee benefits and general and administrative expenses associated with such personnel, capital expenditures, maintenance and repair costs, taxes and direct expenses, including operating expenses and certain allocated operating expenses associated with the ownership and operation of the contributed assets. Spectra Energy and its affiliates charge such expenses based on the cost of actual services provided or using various allocation methodologies based on our percentage of assets, employees, earnings or other measures, as compared to Spectra Energy’s other affiliates.

Transactions with affiliates are summarized in the tables below:

Consolidated Statements of Operations

	2014	2013	2012
	(in millions)		
Operating revenues	$88	$58	$65
Operating, maintenance and other expenses	317	252	218
Interest expense	—	222	260

We are party to an agreement with DCP Midstream, an equity investment of Spectra Energy, in which DCP Midstream processes certain of our customers' gas to meet quality specifications in order to be transported on our system. DCP Midstream processes the gas and sells the NGLs that are extracted from the gas. A portion of the proceeds from those sales are retained by DCP Midstream and the balance is remitted to us. We recognized revenues of $79 million, $48 million and $53 million in 2014, 2013 and 2012, respectively, related to those services, classified as Storage of Natural Gas and Other in our Consolidated Statements of Operations.

We recorded natural gas transmission revenues from DCP Midstream and its affiliates totaling $7 million in 2014 and in 2013 and $8 million in 2012, classified as Transportation of Natural Gas in our Consolidated Statements of Operations.

In addition to the above, we recorded other revenues from DCP Midstream and its affiliates totaling $2 million in 2014, $3 million in 2013 and $4 million in 2012, classified as Storage of Natural Gas and Other in our Consolidated Statements of Operations.

Consolidated Balance Sheets

	December 31,	
	2014	2013
	(in millions)	
Receivables	$—	$17
Current assets — other	3	3
Property, plant and equipment	40	17
Accounts payable	61	60

See also Notes 1, 8 and 14 for discussion of specific related party transactions.

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4. Business Segments

We manage our business in two reportable segments: U.S. Transmission and Liquids. The remainder of our business operations is presented as “Other,” and consists of certain corporate costs.

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

The U.S. Transmission segment provides interstate transmission and storage of natural gas. Substantially all of our operations are subject to the Federal Energy Regulatory Commission (FERC) and the Department of Transportation’s (DOT’s) rules and regulations. Our investments in Gulfstream, SESH and Steckman Ridge are included in U.S. Transmission.

Liquids provides transportation of crude oil and NGLs. The Express-Platte pipeline system is a crude oil pipeline system that connects Canadian and U.S. producers to refineries in the U.S. Rocky Mountain and Midwest regions. These operations are primarily subject to the rules and regulations of the FERC and the National Energy Board (NEB). The Sand Hills and Southern Hills pipelines, which were acquired in the fourth quarter of 2013 in the U.S. Assets Dropdown, provide transportation of NGLs from the Permian Basin and Eagle Ford region to the premium NGL markets on the Gulf Coast, and from the Mid-Continent to Mont Belvieu, Texas, respectively. We have direct one-third ownership interests in Sand Hills and Southern Hills. DCP Midstream and Phillips 66 also each own direct one-third ownership interests in the two pipelines. Sand Hills and Southern Hills are subject to the rules and regulations of the FERC.

Our reportable segments offer different products and services and are managed separately as business units. Management evaluates segment performance based on earnings from continuing operations before interest, taxes, and depreciation and amortization (EBITDA). Cash, cash equivalents and investments are managed centrally, so the gains and losses on foreign currency remeasurement, and interest and dividend income, are excluded from the segments’ EBITDA. Our segment EBITDA may not be comparable to similarly titled measures of other companies because other companies may not calculate EBITDA in the same manner.

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Business Segment Data

	Total Revenues	Segment EBITDA/ Consolidated Earnings Before Income Taxes	Depreciation and Amortization	Capital and Investment Expenditures (a,b)	Assets
	(in millions)				
2014					
U.S. Transmission	$1,939	$1,415	$256	$1,160	$15,182
Liquids	330	240	32	81	2,567
Total	2,269	1,655	288	1,241	17,749
Other	—	(64)	—	—	44
Depreciation and amortization	—	288	—	—	—
Interest expense	—	238	—	—	—
Interest income and other	—	(3)	—	—	—
Total consolidated	$2,269	$1,062	$288	$1,241	$17,793
2013					
U.S. Transmission	$1,727	$1,279	$241	$1,000	$14,174
Liquids	238	132	21	299	2,604
Total	1,965	1,411	262	1,299	16,778
Other	—	(27)	—	—	16
Depreciation and amortization	—	262	—	—	—
Interest expense	—	383	—	—	—
Interest income and other	—	(1)	—	—	—
Total consolidated	$1,965	$738	$262	$1,299	$16,794
2012					
U.S. Transmission	$1,754	$1,251	$231	$930	$13,199
Liquids	—	—	—	513	517
Total	1,754	1,251	231	1,443	13,716
Other	—	(9)	—	—	169
Depreciation and amortization	—	231	—	—	—
Interest expense	—	407	—	—	—
Interest income and other	—	1	—	—	—
Total consolidated	$1,754	$605	$231	$1,443	$13,885

(a) Excludes the $2,210 million net cash outlay for the U.S. Assets Dropdown in 2013, the $343 million cash outlay for the acquisition of Express-Platte in 2013 and the $319 million acquisition of M&N U.S. in 2012.
(b) Excludes a $71 million loan to an unconsolidated affiliate in 2013.

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Geographic Data (a)

	U.S.	Canada	Consolidated
	(in millions)		
2014			
Consolidated revenues			