Spectra Energy Partners, LP
Form 10-K
February 16, 2018
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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, 2017
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 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 (§229.405 of this chapter) 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", "smaller reporting company" and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer x Accelerated filer ¨ Non-accelerated filer ¨ Smaller reporting company ¨
Emerging growth company ¨

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

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ¨

Estimated aggregate market value of the Common Units held by non-affiliates of the registrant at June 30, 2017: $3,426,000,000. As used in this report, the term "common units" refer to common units representing limited partner interests in the registrant, and the term "unitholders" refer to holders of common units.

At January 31, 2018, there were 484,885,418 Common 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 cyber threats, terrorist attacks and any consequential or other hostilities;
- interruption of our operations due to social, civil or political events or unrest;
- 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.

The term “Enbridge” as used in this report refers collectively to Enbridge Inc. and its subsidiaries other than us, unless the context suggests otherwise.

Our operations and activities are managed by our general partner Spectra Energy Partners (DE) GP, LP (our general partner or GP, LP), which in turn is managed by its general partner Spectra Energy Partners GP, LLC (GP, LLC). GP, LLC is indirectly wholly owned by Spectra Energy Corp (Spectra Energy). The term “General Partner” means, as context requires, GP, LP in its capacity as our general partner, or GP, LP and GP, LLC collectively, with GP, LLC acting in its capacity as general partner of GP, LP, in GP,LP.

On February 27, 2017, Enbridge Inc. and Spectra Energy completed a merger transaction (the Merger) resulting in Spectra Energy being a wholly-owned subsidiary of Enbridge. As a result of the Merger, we became an indirect subsidiary of Enbridge through Enbridge’s ownership of Spectra Energy. As of December 31, 2017, Enbridge, through its ownership of Spectra Energy, collectively owned 74% of us and the remaining 26% was publicly owned.

On January 21, 2018, we entered into an Equity Restructuring Agreement, with our GP, LP, (the Equity Restructuring Agreement), pursuant to which the incentive distribution rights and the 2% general partner interest in us held by our GP, LP were converted into 172,500,000 newly issued common units and a non-economic general partner interest in us (the GP/IDR Restructuring). Distributions by us with a record date after January 31, 2018, including the distribution with respect to the fourth quarter 2017, will be made based on the terms of our limited partnership agreement, in effect at the time a distribution is declared. Immediately after the execution of our Equity Restructuring Agreement, a new limited partnership agreement was entered into. As of January 21, 2018, as a result of GP/IDR Restructuring, Enbridge, through its ownership of Spectra Energy, collectively owns approximately 83% of our outstanding common units.

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General

Spectra Energy Partners, through its subsidiaries and equity affiliates, is engaged in the transmission, storage and gathering of natural gas, and the transportation and storage of crude oil, through interstate pipeline systems in the United States and Canada with approximately 16,000 miles of transmission and transportation pipelines, the storage of natural gas in underground facilities with aggregate working gas storage capacity of approximately 170 billion cubic feet (Bcf) and crude oil storage of approximately 5.6 million barrels.

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. 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, oil refineries, and exploration and production companies. Our interstate gas transmission pipeline and storage operations and our crude oil transportation and storage operations are regulated by 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

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intrastate storage operations and Ozark gathering facilities, which are subject to oversight by various state commissions.

In March 2013, Spectra Energy acquired 100% of the ownership interests in the Express-Platte crude oil pipeline system from third-parties. Later in 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, LLC (Algonquin), the remaining ownership interest in Express US, an additional 39% interest in Maritimes & Northeast Pipeline, L.L.C (M&N U.S.), 33% interests in both DCP Sand Hills Pipeline, LLC (Sand Hills) and DCP Southern Hills Pipeline, LLC (Southern Hills), an additional 1% interest in Gulfstream Natural Gas System, L.L.C. (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, LLC (Market Hub), a 49% interest in Steckman Ridge, LP (Steckman Ridge), and Texas Eastern's and Express-Platte's storage facilities.

In November 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 final transaction related to the U.S. Assets Dropdown occurred in November 2015, and consisted of the acquisition of Spectra Energy's remaining 0.1% interest in SESH.

The U.S. Assets Dropdown has been accounted for as an acquisition under common control, resulting in the recast of our prior results. See Note 3 of Notes to Consolidated Financial Statements for further discussion of the transaction.

In October 2015, Spectra Energy acquired our 33.3% ownership interests in Sand Hills and Southern Hills.

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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 5 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 nine 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, LLC (Big Sandy), Gulfstream, SESH and Sabal Trail Transmission, LLC. (Sabal Trail). 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, the first of which has one to four large-diameter parallel pipelines and the other with one to three large-diameter pipelines. Texas Eastern's onshore system consists of approximately 9,070 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 75 Bcf, owned by Market Hub and Bobcat.

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Algonquin

The Algonquin natural gas transmission system, which we directly own 92%, 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 1,140 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.

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Maritimes & Northeast Pipeline

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 northeastern Massachusetts to the border of Canada near Baileyville, Maine. M&N U.S. is connected to the Canadian portion of the Maritimes & Northeast Pipeline system, Maritimes & Northeast Pipeline Limited Partnership (M&N Canada), which is owned 78% by Spectra Energy. M&N U.S. facilities include compressor stations, with a market delivery capability of approximately 0.8 billion cubic feet per day (Bcf/d) of natural gas. The pipeline's location and key interconnects with our transmission system link regional natural gas supplies to the northeast U.S. markets.

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Ozark

Ozark Gas Transmission consists of an approximately 365-mile natural gas transmission system extending from southeastern Oklahoma through Arkansas to southeastern Missouri. Ozark Gas Gathering consists of an approximately 330-mile natural gas gathering system, with associated compressor stations, that primarily serves Arkoma basin producers in eastern Oklahoma.

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Big Sandy

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

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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Sabal Trail

Sabal Trail is an approximately 515-mile interstate natural gas transmission system, with associated laterals and compressor stations, and provides natural gas transportation services for power generation needs to markets in Florida. Sabal Trail is owned 50% directly by us, 42.5% by US Southeastern Gas Infrastructure, LLC (NextEra), and 7.5% by Duke Energy Corporation (Duke) and operated by us. As of July 1, 2017, our investment in Sabal Trail is accounted for under the equity method of accounting.

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Southeast Supply Header

SESH, an approximately 290-mile natural gas transmission system, with associated compressor stations, is operated jointly by Spectra Energy and Enable Gas Transmission, LLC (Enable). 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 six major interconnections. SESH extends to Alabama, interconnecting with 14 major north-south pipelines and three high-deliverability storage facilities. SESH is owned 50% directly by us and 50% by Enable Midstream Partners, LP, collectively. Our investment in SESH is accounted for under the equity method of accounting.

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Market Hub

Market Hub owns and operates two natural gas storage facilities, Moss Bluff and Egan, with a total storage capacity of approximately 46 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 ten interconnections serving 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 29 Bcf salt dome facility, is strategically located on the Gulf Coast near Henry Hub, interconnecting with five major interstate pipelines, including Texas Eastern.

Steckman Ridge

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, 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, fuel oils and renewable energy. Factors that influence

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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. See Note 2 of the Notes to Consolidated Financial Statements for further discussion on our significant customer.

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Liquids

Our Liquids business provides transportation and storage of crude oil for customers in central United States and Canada. Our Liquids pipeline system consists of Express-Platte.

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

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 and crude oil storage of approximately 5.6 million barrels. The Express pipeline carries crude oil to U.S. refining markets in the Rocky Mountains 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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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.

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 pipeline 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 pipeline capacity and all Platte pipeline capacity is used by uncommitted shippers who only pay for the pipeline capacity that is actually used in a given month.

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

Regulations
Most of our U.S. gas transmission, crude oil pipeline and storage operations are regulated by the FERC. The FERC regulates natural gas transmission 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. For more information on pipeline safety matters, see Part I. Item 1A. Risk Factors.

Express-Platte 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.

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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, generators or arrangers 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, transported and disposed 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, transported and disposed in compliance with such regulations.
- U.S. Department of the Interior regulations, which relate to offshore oil and natural gas operations in U.S. waters and impose obligations for establishing financial assurances for decommissioning activities, liabilities for pollution cleanup costs resulting from operations, and potential liabilities for pollution damages. Our offshore facilities operating in federal waters are subject to these regulatory obligations and liabilities.
- 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.
- The Endangered Species Act, which restricts activities that may affect federally identified endangered and threatened species or their habitats through the implementation of operating restrictions or a temporary, season, or permanent ban in affected areas. Our expansion and other construction activities must consider the potential impact of those activities on endangered and threatened species or their habitats.

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.
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The Canadian Environmental Assessment Act, 2012 (CEAA 2012) requires the NEB to consider potential environmental effects in its decisions for designated projects. The NEB under its enabling statute also

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

For more information on environmental matters, including possible liability and capital costs, see Part I. Item 1A. Risk Factors and Part II. Item 8. Financial Statements and Supplementary Data, Notes 6 and 18 of Notes to Consolidated Financial Statements.

Except to the extent discussed in Notes 6 and 18, 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 5 and 16 of Notes to Consolidated Financial Statements.

Employees

We do not have any employees. We are managed by the directors and officers of our General Partner. As of December 31, 2017, our General Partner and its affiliates have approximately 2,100 employees performing services for our operations, and are solely responsible for providing the employees and other personnel necessary to conduct our operations.

Insurance

Our operations are subject to many hazards inherent in the natural gas gathering and processing, transmission and storage activities and crude oil transportation and storage industry. Our assets may experience physical damage as a result of an accident or natural disaster. These hazards can also cause personal injury and loss of life, severe damage to and destruction of property and equipment, pollution or environmental damage, and suspension of operations. We are included in the comprehensive insurance program maintained by Enbridge for its subsidiaries. This program includes insurance coverage in types and amounts and with terms and conditions that are generally consistent with coverage considered customary for our industry.

In the unlikely event multiple insurable incidents occur which exceed coverage limits within the same insurance period, the total insurance coverage will be allocated among the Enbridge entities on an equitable basis based on an insurance allocation agreement we have entered into with Enbridge and other Enbridge subsidiaries.

We can make no assurance that the insurance coverage we maintain will be available or adequate for any particular risk or loss or that we will be able to maintain adequate insurance in the future at rates we consider reasonable. Although we believe that our assets are adequately covered by insurance, a substantial uninsured loss could have a material adverse effect on our financial position, results of operations and cash flows.

Our Partnership Agreement

On January 21, 2018, immediately after the entry into the Equity Restructuring Agreement, our General Partner executed and delivered the Third Amended and Restated Agreement of Limited Partnership of Spectra Energy Partners, LP (our partnership agreement) to, among other matters, reflect the GP/IDR Restructuring.

Set forth below is a summary of the material provision of our partnership agreement that relates to available cash:

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

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(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 distributions for any one or more of the next four quarters;
provided, however, 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.

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

Our cash distributions are not guaranteed. The cash from operations that we generate could decrease or fail to meet expectations, either of which could reduce our ability to pay quarterly cash distributions
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 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;
- shareholder activism and activities by non-governmental organizations to limit certain sources of funding for the energy sector or restrict the exploration, development and production of oil and gas;
- 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 distributable cash flow does not depend solely on profitability, which is affected by non-cash items. As a result, we could pay cash distributions during periods when we record net losses and could be unable to pay cash distributions during periods when we record net income. In addition, the amount of cash we generate from operations is affected by numerous factors beyond our control, fluctuates from quarter to quarter and may change over time. Significant or sustained reductions in the cash generated by our operations could reduce our ability to pay quarterly distributions. Any failure to pay distributions at expected levels could result in a loss of investor confidence and a decrease in the value of our unit price.

Our subsidiaries and equity investments 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 13% of our distributable cash flow in 2017. We operate Steckman Ridge and Sabal Trail. Spectra Energy shares operations of SESH with Enable, and we share operations of Gulfstream with Williams. 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 investments 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 transmission 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 transmission pipeline systems, crude oil transportation pipeline systems and certain of our storage facilities and related assets are subject to regulation by the FERC with respect to operations in the U. S. and the NEB with respect to operations in Canada. 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.

Effective January 2018, the 2017 Tax Cuts and Jobs Act changed several provisions of the federal tax code, including a reduction in the maximum corporate tax rate. Following the 2017 Tax Cuts and Jobs Act being signed into law, filings have been made at FERC requesting that FERC require natural gas and liquids pipelines to lower their transportation rates to account for lower taxes. Following the effective date of the law, FERC orders granting certificates to construct proposed natural gas pipeline facilities have directed pipelines proposing new rates for service on those facilities to re-file such rates so that the rates reflect the reduction in the corporate tax rate, and FERC has issued data requests in pending certificate proceedings for proposed natural gas pipeline facilities requesting pipelines to explain the impacts of the reduction in the corporate tax rate on the rate proposals in those proceedings and to provide re-calculated initial rates for service on the proposed pipeline facilities. FERC may enact other regulations or issue further requests to pipelines regarding the impact of the corporate tax rate change on the rates. However, FERC’s establishment of a just and reasonable rate is based on many components, and the reduction in the corporate tax rate may only impact two of such components, the allowance for income taxes and the amount for accumulated deferred income taxes. Because our existing jurisdictional rates were established based on a higher corporate tax rate, FERC or our shippers may challenge these rates in the future, and the resulting new rate may be lower than the rates we currently charge.

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.

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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 2017, 53% 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, Enbridge 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, fuel oils and renewable energy.

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 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 in our areas of operation may cause customers to seek alternative energy resources, which could materially affect our revenues, earnings and cash flows.

Our business is dependent on the continued availability of oil and natural gas production and reserves. The development of additional oil and natural gas reserves requires significant capital expenditures by others for exploration and development drilling and the installation of production, gathering, storage, transportation and other facilities that permit oil and natural gas to be produced and delivered to our assets. Low prices for oil and natural gas, regulatory limitations or the lack of available capital for these projects could adversely affect the development and production of additional reserves, as well as gathering, storage, pipeline transmission and import and export of oil and natural gas supplies, which could adversely impact our ability to fill the capacities of our gathering, transmission, storage and processing facilities.

Production from existing wells and oil and natural gas supply basins with access to our pipeline systems and storage facilities will naturally decline over time. The amount of oil and natural gas reserves underlying these wells may also be less than anticipated, and the rate at which production from these reserves declines may be greater than anticipated. Additionally, the competition for oil and natural gas supplies to serve other markets could reduce the amount of oil and natural gas supply for our customers. Accordingly, to maintain or increase the contracted capacity or the volume of oil and natural gas transported or stored in our assets, our customers must compete with others to obtain adequate supplies of oil and natural gas.

Demand for our services depends on the ability and willingness of customers with access to our facilities to satisfy demand in the markets we serve by deliveries through our pipelines. Any decrease in this demand could

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adversely affect our business. Demand for oil and natural gas is also affected by weather, future industrial and economic conditions, fuel conservation measures, alternative fuel requirements, governmental regulation, and technological advances in fuel economy and energy generation devices, all of which are matters beyond our control. If new supplies of oil and natural gas are not obtained to replace the natural decline in volumes from existing supply areas, or if oil and natural gas supplies are diverted to serve other markets, the overall volume of oil and natural gas transported or stored in our assets would decline, which could have a material effect on our revenues, earnings and cash flows, including our ability to make distributions.

We may be unable to secure renewals of long-term transportation or storage agreements at favorable rates or on a long-term basis or at all.

We may be unable to secure renewals of long-term transportation or storage agreements in the future for our natural gas transmission and crude oil transportation businesses as a result of economic factors, changing gas supply flow patterns in North America, increased competition or changes in regulation. If an existing customer breaches its long-term transportation or storage contract or terminates such contract at the expiration of its term, we may be subject to a loss of revenue if we are unable to promptly resell the capacity to other customers. Our ability to execute a long-term transportation or storage contract with one or more replacement customers on substantially equivalent terms and conditions is uncertain and depends on a number of factors beyond our control, including:

- the timing, volume and location of new market demands;
- competition from alternative sources of fuels and other supply basins;
- the supply and price of oil and natural gas accessible by our system;
- the demand for oil and natural gas in markets served by us;
- whether the market will continue to support long-term firm contracts;
- the effects of state regulation on customer contracting practices; and
- the availability and competitiveness of alternative transportation and storage services in the markets we serve.

Any failure to extend or replace a significant portion of our existing contracts may have a material adverse effect on 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.

We may face opposition to the operation or expansion of our pipelines and facilities from various groups.

We may face opposition to the operation or expansion of our pipelines and facilities from environmental groups, landowners, tribal groups, local groups and other advocates. Such opposition could take many forms, including organized protests, attempts to block or sabotage our operations, intervention in regulatory or administrative proceedings involving our assets, or lawsuits or other actions designed to prevent, disrupt or delay the operation of our assets and business. For example, repairing our pipelines often involves securing consent from individual landowners to access their property; one or more landowners may resist our efforts to make needed repairs, which could lead to an interruption in the operation of the affected pipeline or facility for a period of time that is significantly longer than would have otherwise been the case. In addition, acts of sabotage or eco-terrorism could cause significant damage or injury to people, property or the environment or lead to extended interruptions of our operations. Any event that interrupts the revenues generated by our operations, that delays or reduces anticipated revenues, or that causes us to make significant expenditures not covered by insurance, could reduce our cash available for paying distributions and adversely affect our financial condition.

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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.
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.
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;

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- 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 in the U.S. 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, including those pipelines where a leak or rupture could harm high consequence areas such as high population areas and unusually sensitive ecological areas. The regulations determine the pressures at which our pipelines can operate.

New legislation or regulations adopted by PHMSA may impose more stringent requirements applicable to integrity management programs and other pipeline safety aspects of our operations, which could cause us to incur increased capital costs, operational delays and costs of operations. PHMSA adopted pipeline safety legislation in 2011 and, more recently, in 2016 that, among other things, increased the penalties for safety violations, established additional safety requirements for newly constructed pipelines and required studies of safety issues that could result in the adoption of new regulatory requirements by PHMSA for existing pipelines, and empowered PHMSA to address imminent hazards by imposing emergency restrictions, prohibitions and safety measures on owners and operators of regulated pipeline facilities without prior notice or an opportunity for a hearing. PHMSA issued interim regulations in October 2016 to implement the agency's expanded authority to address unsafe pipeline conditions or practices that pose an imminent hazard to life, property, or the environment.

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. Additionally, PHMSA will establish standards for storage facilities. Proposed rulemaking on these matters has not been finalized and 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.

PHMSA was recently granted authority by the U.S. Congress to govern safety relating to underground natural gas storage facilities, and in particular, relating to downhole facilities, including well integrity, wellbore tubing, and casing. In December 2016, PHMSA issued final interim rules that impose new safety-related requirements on downhole facilities of new and existing underground natural gas storage facilities. The regulations incorporate standards for design, operations, and functional integrity of underground storage wells. PHMSA indicated when it issued the interim final rule that the adoption of these safety standards for natural gas storage facilities represent a first step in a multi-phase process to enhance the safety of underground natural gas storage, with more standards likely forthcoming. Most recently, in response to a petition for reconsideration of the interim final rule received in January 2017, PHMSA published a notice in June 2017, advising that the agency intends to consider the issues raised by the petitioners in a final rule, which it currently expects to issue in 2018. At this time, we cannot predict the impact of any future regulatory actions in this area and can provide no assurance that our future costs to comply with existing or new standards relating to underground natural gas storage facilities will not have a material adverse effect on our business and operating results.

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 pipelines.

As in the U.S., several legislative changes addressing pipeline safety in Canada have recently come into force. The changes evidence an increased focus on the implementation of management systems to address key areas such as emergency management, integrity management, safety, security and environmental protection. Other legislative changes have created authority for the NEB to impose administrative monetary penalties for non-compliance with the regulatory regime it administers.

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

Restrictions in our financing arrangements 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, Enbridge, 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 Enbridge 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 Enbridge, 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 Enbridge, as credit rating agencies may consider the leverage and credit profile of Enbridge and its affiliates because of their ownership interest in and control of us, and the strong operational links between Enbridge 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, including cyber-terrorism, requires significant capital expenditures and a successful terrorist attack could affect our business.

Acts of terrorism and any possible reprisals as a consequence of any action by the U.S. and its allies could be directed against companies operating in the U.S. This risk is particularly relevant for companies, like ours, operating in any energy infrastructure industry that handles volatile gaseous and liquid hydrocarbons. The potential for terrorism, including cyber-terrorism, has subjected our operations to increased risks that could have an adverse effect on our business. In particular, we may experience increased capital and operating costs to implement increased security for our facilities and pipelines, such as additional physical facility and pipeline security, and additional security personnel. Moreover, any physical damage to high profile facilities resulting from acts of terrorism may not be covered, or covered fully, by insurance. We may be required to expend material amounts of capital to repair any facilities, the expenditure of which could adversely affect our business and cash flows. A cyber attack could also lead to a significant interruption in our operations or unauthorized release of confidential or otherwise protected information, which could damage our reputation or lead to financial losses.

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

Cyber-attacks or security breaches could have a material adverse effect on our business, financial condition or results of operations.

Our business is dependent upon information systems and other digital technologies for controlling our plants and pipelines, processing transactions and summarizing and reporting results of operations. The secure processing, maintenance and transmission of information is critical to our operations. A security breach of our network or systems could result in improper operation of our assets, potentially including delays in the delivery or availability of our customers' products, contamination or degradation of the products we transport, store or distribute, or releases of hydrocarbon products for which we could be held liable. Furthermore, we collect and store sensitive data in the ordinary course of our business, including personal identification information of our employees as well as our proprietary business information and that of our customers, suppliers, investors and other stakeholders. We conduct cyber security audits from time to time and continuously monitor our systems in an effort to mitigate the risk of cyber-attacks or security breaches. Enbridge has a Cybersecurity controls framework in place which has been derived from the NIST Cybersecurity Framework and ISO 27001 standards. We monitor our control effectiveness in an increasing threat landscape and continuously take action to improve our security posture. We have implemented a 7X24 security operations center to monitor, detect and investigate any anomalous activity in our network together with an incident response process that we test on a monthly basis. We conduct independent cyber security audits and penetration tests on a regular basis to test that our preventative and detective controls are working as designed. Despite our security measures, our information systems may become the target of cyber-attacks or security breaches (including employee error, malfeasance or other breaches), which could compromise our network or systems and result in the release or loss of the information stored therein, misappropriation of assets, disruption to our operations or damage to our facilities. Enbridge's current insurance coverage programs do not contain specific coverage for cyber-attacks or security breaches. As a result of a cyber-attack or security breach, we could also be liable under laws that protect the privacy of personal information, subject to regulatory penalties, experience damage to our reputation or a loss of consumer confidence in our products and services, or incur additional costs for remediation and modification or enhancement of our information systems to prevent future occurrences, all of which could have a material and adverse effect on our business, financial condition or results of operations.

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We do not insure against all potential losses and could be seriously harmed by unexpected liabilities or by the inability of our insurers to satisfy our claims.

Our assets and operations are covered under insurance programs maintained by Enbridge for its subsidiaries and affiliates. Enbridge's comprehensive insurance programs are maintained on a consolidated basis to include the operations of its subsidiaries, including us. We are not fully insured against all risks inherent to our business, including environmental accidents that might occur. If a significant accident or event occurs that is not fully insured, it could adversely affect our operations and financial condition. In addition, we may not be able to maintain or obtain insurance of the type and amount we desire at reasonable rates. Changes in the insurance markets occasionally make it more difficult for us to obtain certain types of coverage at reasonable rates, and we may elect to self-insure a portion of our asset portfolio. In addition, we do not maintain offshore business interruption insurance. There can be no assurance that we will be able to obtain the levels or types of insurance we would otherwise have obtained prior to these market changes or that the insurance coverage we do obtain will not contain large deductibles or fail to cover certain hazards or cover all potential losses. The occurrence of any operating risks not fully covered by insurance could have a material adverse effect on our cash flows, financial condition and results of operations. In addition, in the unlikely event there is a total or partial loss of our assets or storage facilities, any insurance proceeds that we may receive in respect thereof may not be sufficient in any particular situation to effect a restoration of our assets or facilities to the condition that existed prior to such loss or sufficient to satisfy our obligations under the notes. In addition, in the event that multiple insurable incidents that, in the aggregate, exceed coverage limits and occur within the same insurance period, the total insurance coverage will be allocated among the Enbridge entities covered thereby on an equitable basis based on an insurance allocation agreement we have entered into with Enbridge and other Enbridge subsidiaries.

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 and oil. 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 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 and oil, 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; and
- capacity and transmission service into, or out of, our markets.

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

Our U.S. assets and operations are subject to regulation by various federal, state and local authorities, including regulation by the FERC and by various authorities under federal, state and local environmental laws. Our 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 renewable energy, as well as traditional pipeline competitors. Increased competition driven by regulatory changes could have a material effect on our business, earnings, financial condition and cash flows.

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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 delay or 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.

The current FERC Chairman announced in December 2017 that FERC will review its policies on certification of natural gas pipelines, including an examination of its long-standing Policy Statement on Certification of New Interstate Natural Gas Pipeline Facilities, issued in 1999, that is used to determine whether to grant certificates for new pipeline projects. We are unable to predict what, if any, changes may be proposed that will affect our natural gas pipeline business or when such proposals, if any, might become effective. We do not expect that any change in this policy would affect us in a materially different manner than any other similarly sized natural gas pipeline company operating in the United States.

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.

We are subject to numerous environmental laws and regulations affecting many aspects of our present and future operations, including air emissions, water quality, wastewater discharges, solid waste and hazardous waste. These laws and regulations can result in increased capital, operating and other costs. These laws and regulations generally require us to obtain and comply with a wide variety of environmental licenses, permits, inspections and other approvals. Compliance with environmental laws and regulations can require significant expenditures, including expenditures for cleanup costs and damages arising out of contaminated properties. In particular, compliance with major CAA regulatory programs is likely to cause us to incur significant capital expenditures to obtain permits, evaluate offsite impacts of our operations, install, upgrade or replace pollution control equipment, and otherwise assure compliance. Some states in which we operate are implementing new emissions limits to comply with 2008 ozone standards regulated under the National Ambient Air Quality Standards. In 2015, the ozone standards were lowered even further from 75 parts per billion (ppb) to 70 ppb. The EPA published a final rule in November 2017 that issued area designations with respect to ground-level ozone for approximately 85% of the U.S. counties as either "attainment/unclassifiable" or "unclassifiable" and is expected to issue non-attainment designations for the remaining areas of the U.S. not addressed under the November 2017 final rule in the first half

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of 2018. States are also expected to implement regulations implementing the NAAQS rule that may be more stringent than the federal standards. The precise nature of these compliance obligations at each of our facilities has not been finally determined and may depend in part on future regulatory changes. In addition, compliance with new and emerging environmental regulatory programs is likely to significantly increase our operating costs compared to historical levels.

In the U.S., climate change continues to attract considerable public and scientific attention. As a result, numerous proposals have been made and could continue to be made at the federal, regional and state levels of government to monitor and limit emissions of GHGs through consideration of cap-and-trade programs, carbon taxes, GHG reporting and tracking programs, and regulations that directly limit GHG emissions from certain sources. 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 permitted emissions of GHGs, (except to the extent that some GHGs consist of volatile organic compounds and nitrous oxides that are subject to emission limits). In June 2016, the EPA published a final rule requiring certain new, modified or reconstructed facilities in the oil and natural gas sector to reduce these methane gas and volatile organic compound emissions. However, in June 2017, the EPA proposed a rule to stay certain portions of the June 2016 rule for two years and reconsider the entirety of the 2016 rule but has not yet published a final rule and, as a result, the 2016 rule remains in effect but future implementation of that rule is uncertain at this time. Additionally, while the U.S. joined the international community in meeting on climate change issues and preparing an agreement that became known as the “Paris Agreement,” which set non-binding GHG emissions reduction goals for member counties and was signed by the U.S. in November 2016, with the change in Presidential Administrations, the U.S. State Department informed the United Nations in August 2017 of the intent of the U.S. to withdraw from the Paris Agreement. In Canada, the federal government has committed to reducing GHGs and emissions, including becoming signatory and being committed to the Paris Agreement. In addition, a number of Canadian provinces have joined regional GHG initiatives or are developing their own programs that would mandate reductions in GHG emissions. In the U.S., Canada and other countries, public interest groups and regulatory agencies are increasingly focusing on the emission of methane associated with natural gas development and transmission as a source of GHG emissions. Both the US and Canada have developed regulations to find and fix methane leaks. However, as the key details of future GHG restrictions and compliance mechanisms remain undefined, the likely future effects on our business are uncertain. Recently, activists concerned about the potential effects of climate change have directed their attention at sources of funding for fossil-fuel energy companies, which has resulted in certain financial institutions, funds and other sources of capital restricting or eliminating their investment in oil and natural gas activities. Ultimately, this could make it more difficult to secure funding for exploration and production or midstream activities. Notwithstanding potential risks related to climate change, the International Energy Agency estimates that global energy demand will continue to rise and will not peak until after 2040 and that oil and natural gas will continue to represent a substantial percentage of global energy use over that time.

Failure to comply with environmental regulations may result in the imposition of fines, penalties and injunctive measures affecting our operating assets. In addition, changes in environmental laws and regulations or the enactment of new environmental laws or regulations could result in a material increase in our cost of compliance with such laws and regulations. We may not be able to obtain or maintain all required environmental regulatory approvals for our operating assets or development projects. If there is a delay in obtaining any required environmental regulatory approvals, if we fail to obtain or comply with them or if environmental laws or regulations change or are administered in a more stringent manner, the operations of facilities or the development of new facilities could be prevented, delayed or become subject to additional costs. We expect that costs we incur to comply with environmental regulations in the future will have a significant effect on our earnings and cash flows.

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 requirements, which could delay proposed construction projects.

Natural gas transmission and storage 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

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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. 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 do not own all of the land on which our pipelines and facilities are located, which could result in disruptions to our operations.

We do not own all of the land on which our pipelines and facilities have been constructed, and we are, therefore, subject to the possibility of more onerous terms and/or increased costs to retain necessary land use if we do not have valid rights-of-way or if such rights-of-way lapse or terminate. We obtain the rights to construct and operate our pipelines on land owned by third parties and governmental agencies for a specific period of time. Additionally, following a recent decision issued in May 2017 by the federal Tenth Circuit Court of Appeals, tribal ownership of even a very small fractional interest in an allotted land, that is, tribal land owned or at one time owned by an individual Indian landowner, bars condemnation of any interest in the allotment. Consequently, the inability to condemn such allotted lands under circumstances where an existing pipeline rights-of-way may soon lapse or terminate serves as an additional impediment for pipeline operators. We cannot guarantee that we will always be able to renew existing rights-of-way or obtain new rights-of-way without experiencing significant costs. Any loss of rights with respect to our real property, our loss of these rights, through our inability to renew right-of-way contracts or otherwise, could have a material adverse effect on our business, results of operations, financial position and ability to make cash distributions to our unitholders.

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 and oil producers may be the primary customer, our credit exposure with below investment-grade customers may increase. While we monitor these situations carefully and take appropriate measures when deemed necessary, it is possible that customer payment defaults, if significant, could have a material effect on our earnings and cash flows.

Our long-term firm transportation and storage contracts obligate our customers to pay reservation charges regardless of whether they transport oil or natural gas on our pipeline systems or store oil or natural gas in our storage facilities, subject to the customer's right to receive a credit to the extent we are unable, due to an event of force majeure, to transport or store volumes of oil or natural gas up to the customer's contracted capacity. As a result, absent an event of force majeure, a significant portion of our business will generally depend on our customers' financial condition and ability to pay rather than upon the amount of natural gas transported or stored. A customer subject to a bankruptcy filing may elect to reject its transportation or storage contract. Prior to such an election, we will not be able to terminate the bankrupt customer's transportation or storage contract and replace the customer absent approval of the bankruptcy court. In addition, a bankruptcy court may avoid security provided, or certain payments made, by a bankrupt customer and deny us priority status with respect to volumes paid for but not delivered.

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Risks Inherent in an Investment in Us

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

Enbridge owns and controls our General Partner. Some of our General Partner's directors, and some of its executive officers, are directors or officers of Enbridge or its affiliates. Although our General Partner has a fiduciary duty to manage us in a manner beneficial to Enbridge 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 Enbridge. Therefore, conflicts of interest may arise between Enbridge 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 Enbridge to pursue a business strategy that favors us. Enbridge's directors and officers have a fiduciary duty to make these decisions in the best interests of the owners of Enbridge, 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 Enbridge and its affiliates, in resolving conflicts of interest;
- Enbridge and its affiliates are not limited in their ability to compete with us;
- some officers of Enbridge who provide services to us also devote significant time to the business of Enbridge and will be compensated by Enbridge for the services rendered to it;
- 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, the amount of any cash reserves that in its reasonable discretion are necessary to fund our future operating expenditures. In addition, our partnership agreement permits our General Partner to reduce available cash by establishing cash reserves for the proper conduct of our business, to comply with applicable laws or agreements to which we are a party or to provide funds for future distributions to partners. These determinations 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 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 90% 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.

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Affiliates of our General Partner 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, Enbridge and others prohibits affiliates of our General Partner from owning assets or engaging in businesses that compete directly or indirectly with us. In addition, Enbridge 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 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 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

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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.

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 the board of directors of our General Partner (the 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, including the independent directors, will be chosen entirely by owners of the General Partner and not by our unitholders. Furthermore, if the unitholders were dissatisfied with the performance of the general partner of our 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 presently remove our General Partner without its consent.

The unitholders will be unable to remove our General Partner without its consent because our 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, 2018, our General Partner and its affiliates own 83% 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% equity interests in Gulfstream, SESH, Steckman Ridge and Sabal Trail. 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 (Investment Company Act), 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

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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 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 our 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 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 unitholders' approval, which would dilute our existing 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.

Enbridge 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, 2018, Enbridge and its affiliates hold an aggregate of 402,989,862 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 unitholder to sell the units at an undesirable time or price.

If at any time our General Partner and its affiliates own more than 90% 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 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 unitholder may also incur a tax liability upon a sale of their units. As of January 31, 2018, our General Partner and its affiliates own approximately 83% of our outstanding common units.

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Our 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 unitholders could be liable for any and all of our obligations as if our 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 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.

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 our 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 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. If the Internal Revenue Service (IRS) treats us as a corporation or we otherwise become subject to a material amount of entity-level taxation for federal and 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 and not becoming subject to a material amount of federal or state taxation. 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 21% 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 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 unitholder, likely causing a substantial reduction in the value of our common units.

Under current law, for taxable years beginning after December 31, 2017, we may be required to pay federal income tax as the result of an audit adjustment (as further described below). Furthermore, 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 other 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,

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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.

The U.S. federal income tax treatment of publicly traded partnerships or an investment in our common units could be subject to potential legislative, judicial, or administrative changes and differing interpretations, possibly on a retroactive basis.

The present federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by administrative or legislative action or judicial interpretation at any time. From time to time, members of the U.S. Congress, the Treasury Department and the IRS have proposed and considered substantive changes to the existing federal income tax laws that affect publicly traded partnerships. Although there is no current legislative proposal, a prior legislative proposal would have eliminated the qualifying income exception to the treatment of all publicly traded partnerships as corporations, upon which we rely for our treatment as a partnership for U.S. federal income tax purposes. We are unable to predict whether similar legislative or regulatory changes or other proposals will ultimately be enacted or adopted. However, it is possible that a change in the law could affect us and may be applied retroactively. Any such changes could negatively impact the value of an investment in our units.

Moreover, while we believe the income that we treat as qualifying income satisfies the requirements for qualifying income under applicable legal requirements, including the recently-finalized qualifying income Treasury Regulations, the IRS could take a position that is contrary to our interpretation of (a) Section 7704 of the Internal Revenue Code of 1986, (b) the final qualifying income Treasury Regulations, or (c) other applicable guidance.

If for any reason we are taxable as a corporation in any taxable year, our items of income, gain, loss and deduction would be taken into account by us, in determining the amount of our liability for federal income tax, rather than being passed through to our unitholders. Our taxation as a corporation would materially reduce the cash available for distribution to unitholders and thus would likely substantially reduce the value of our units. Any distribution made to a unitholder at a time we are treated as a corporation would be (i) a taxable dividend to the extent of our current or accumulated earnings and profits, then (ii) a nontaxable return of capital to the extent of the unitholder's adjusted tax basis in its units (determined separately for each unit), and thereafter (iii) taxable capital gain.

You are urged to consult with your own tax advisor with respect to the status of regulatory or administrative developments and proposals and their potential effect on your investment in our common units.

If the IRS makes audit adjustments to our income tax returns for tax years beginning after December 31, 2017, it (and some states) may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustments directly from us, in which case our cash available for distribution to our unitholders might be substantially reduced and our current and former unitholders may be required to indemnify us for any taxes (including any applicable penalties and interest) resulting from such audit adjustments that were paid on such unitholders' behalf.

Pursuant to the Bipartisan Budget Act of 2015, for tax years beginning after December 31, 2017, if the IRS makes audit adjustments to our income tax returns, it (and some states) may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustments directly from us. To the extent possible under the new rules, our General Partner may elect to either pay the taxes (including any applicable penalties and interest) directly to the IRS or, if we are eligible, issue a revised information statement to each unitholder and former unitholder with respect to an audited and adjusted return. Although our General Partner may elect to have our unitholders and former unitholders take such audit adjustment into account and pay any resulting taxes (including applicable penalties or interest in accordance with their interests in us during the tax year under audit, but there can be no assurance that such election will be practical, permissible or effective in all circumstances. As a result, our current unitholders may bear some or all of the tax liability resulting from such audit adjustment, even if such unitholders did not own units in us during the tax year under audit. If, as a result of any such audit adjustment, we are required to make payments of taxes, penalties and interest, our cash available for distribution to our unitholders might be substantially reduced and our current and former unitholders may be required to indemnify us for any taxes (including any applicable penalties and interest) resulting from such audit adjustments that were paid on such unitholders' behalf. These rules are not applicable for tax years beginning on or prior to December 31, 2017.

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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, unitholders are required to pay any federal income taxes and, in some cases, state and local income taxes on the unitholder's share of taxable income even if the unitholders receive no cash distributions from us. The 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.

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

If the unitholder sells its common units, the unitholder will recognize a gain or loss equal to the difference between the amount realized and the unitholder's tax basis in those common units. Because distributions in excess of the unitholder's allocable share of our net taxable income decrease the 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. In addition, because the amount realized includes the share of our nonrecourse liabilities, if the unitholder sells the units, the unitholder may incur a tax liability in excess of the amount of cash the unitholder received from the sale.

A substantial portion of the amount realized from a unitholder's sale of our common units, whether or not representing gain, may be taxed as ordinary income to such unitholder due to potential recapture items, including depreciation recapture. Thus, a unitholder may recognize both ordinary income and capital loss from the sale of common units if the amount realized on a sale of such common units is less than such unitholder's adjusted basis in the common units. Net capital loss may only offset capital gains and, in the case of individuals, up to $3,000 of ordinary income per year. In the taxable period in which a unitholder sells its common units, such unitholder may recognize ordinary income from our allocations of income and gain to such unitholder prior to the sale and from recapture items that generally cannot be offset by any capital loss recognized upon the sale of common units.

Tax-exempt entities 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 employee benefit plan and individual retirement accounts (IRAs), 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. Further, with respect to taxable years beginning after December 31, 2017, a tax-exempt entity with more than one unrelated trade or business (including by attribution from investment in a partnership such as ours that is engaged in one or more unrelated trade or business) is required to compute the unrelated business taxable income of such tax-exempt entity separately with respect to each such trade or business (including for purposes of determining any net operating loss deduction). As a result, for years beginning after December 31, 2017, it may not be possible for tax-exempt entities to utilize losses from an investment in our partnership to offset unrelated business taxable income from another unrelated trade or business and vice versa. Tax-exempt entities should consult a tax advisor before investing in our common units.

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Non-U.S. Unitholders will be subject to U.S. taxes and withholding with respect to their income and gain from owning our units.

Non-U.S. unitholders are generally taxed and subject to income tax filing requirements by the United States on income effectively connected with a U.S. trade or business ("effectively connected income"). Income allocated to our unitholders and any gain from the sale of our units will generally be considered to be "effectively connected with a U.S. trade or business. As a result, distributions to a Non-U.S. unitholder will be subject to withholding at the highest applicable effective tax rate and a Non-U.S. unitholder who sells or otherwise disposes of a unit will also be subject to U.S. federal income tax on the gain realized from the sale or disposition of that unit.

The Tax Cuts and Jobs Act imposes a withholding obligation of 10% of the amount realized upon a Non- U.S. unitholder's sale or exchange of an interest in a partnership that is engaged in a U.S. trade or business. However, due to challenges of administering a withholding obligation applicable to open market trading and other complications, the IRS has temporarily suspended the application of this withholding rule to open market transfers of interest in publicly traded partnerships pending promulgation of regulations or other guidance that resolves the challenges. It is not clear if or when such regulations or other guidance will be issued. Non-U.S. unitholders 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 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.

We generally 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 generally prorate our items of income, gain, loss and deduction for federal income tax purposes between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month (the Allocation Date), instead of on the basis of the date a particular unit is transferred. Similarly, we generally allocate certain deductions for depreciation of capital additions, gain or loss realized on a sale or other disposition of our assets and, in the discretion of the General Partner, any other extraordinary item of income, gain, loss or deduction based upon ownership on the Allocation Date. The U.S. Department of the Treasury and the IRS issued final Treasury Regulations in 2015 that permit publicly traded partnerships to use a monthly simplifying convention that is similar to ours, but those regulations do not specifically authorize all aspects of the proration

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method we have adopted. If the IRS were to challenge this method, we could be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

A unitholder whose units are the subject of a securities loan (e.g. 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 there are no specific rules governing the U.S. federal income tax consequence of loaning a partnership interest, a unitholder whose units are the subject of a securities loan may be considered to have disposed of the loaned units. In that case, the unitholder may no longer be treated for tax purposes as a partner with respect to those units during the period of the loan and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan, 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 securities loan are urged to consult a tax advisor to determine whether it is advisable to modify any applicable brokerage account agreements to prohibit their brokers from borrowing and lending their units.

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

In addition to federal income taxes, a 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 unitholder does not live in any of those jurisdictions. The 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 unitholder may be subject to penalties for failure to comply with those requirements. It is the unitholder's responsibility to file all United States federal, foreign, state and local tax returns.

Item 1B. Unresolved Staff Comments.

None.

Item 2. Properties.

At December 31, 2017, 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 14 of Notes to Consolidated Financial Statements, none of our properties were secured by mortgages or other material security interests at December 31, 2017.

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 Part I. Item 1. Business.

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Item 3. Legal Proceedings.

Except for the matters described below, we have no material pending legal proceedings that are required to be disclosed hereunder. For more information regarding other legal proceedings, including regulatory and environmental matters, see Note 18 of Notes to Consolidated Financial Statements.

Paul Morris v. Spectra Energy Partners (DE) GP, LP, Spectra Energy Corp, Defendants, and Spectra Energy Partners, LP, Nominal Defendant

A putative class action lawsuit asserting direct and derivative claims was filed in the Delaware Court of Chancery in March of 2016 by Paul Morris (Plaintiff), a unitholder of Spectra Energy Partners. The claims in the lawsuit relate to a transaction in October 2015 whereby 33% ownership interests in the Sand Hills and Southern Hills pipelines were sold by us to Spectra Energy and, subsequent to that transaction, Spectra Energy contributed those ownership interests to DCP Midstream, LLC, a joint venture in which Spectra Energy owns a 50% ownership interest. The lawsuit alleges that the consideration paid to us by Spectra Energy in exchange for those ownership interests was approximately $525 million less than the purported value of such ownership interests. The lawsuit asserted direct and derivative claims of breach of contract and breach of the implied duty of good faith and fair dealing against the General Partner and direct and derivative claims against Spectra Energy of tortious interference with the Second Amended and Restated Agreement of Limited Partnership of Spectra Energy Partners, LP dated as of November 1, 2013, as amended by Amendment No. 1 dated as of July 2, 2015 (our partnership agreement in effect at the time). Spectra Energy Partners is also named as a “nominal” defendant in the lawsuit for the derivative claims.

On January 13, 2017, Plaintiff withdrew all of his direct claims in the lawsuit. On June 27, 2017, the Delaware Court of Chancery issued a Memorandum and Opinion dismissing the derivative claims of tortious interference against Spectra Energy and the breach of the implied duty of good faith and fair dealing against the General Partner, leaving only the derivative claim for breach of our partnership agreement in effect at the time against the General Partner pending. The relief sought in the complaint includes rescission of the transaction, damages, interest and attorneys’ fees.

Sierra Club v. Federal Energy Regulatory Commission, Respondent, and Sabal Trail Transmission, LLC et al., Intervenor-Respondents (D.C. Cir.)

Sierra Club and two other non-governmental organizations filed a Petition for Review of Sabal Trail’s FERC certificate on September 20, 2016 in the D.C. Circuit Court of Appeals. On August 22, 2017, the D.C. Circuit issued an opinion denying one of the petitions, and granting the other petition in part, vacating the certificates, and remanding the case to FERC to supplement the environmental impact statement for the project to estimate the quantity of green-house gases to be released into the environment by the gas-fired generation plants in Florida that will consume the gas transported by Sabal Trail. The court withheld issuance of the mandate requiring vacatur of the certificate until seven days after the disposition of any timely petition for rehearing. On October 6, 2017, Sabal Trail and FERC each filed timely petitions for rehearing. On January 31, 2018, the court denied FERC’s and Sabal Trail’s petitions for rehearing. Absent a stay, the court’s mandate could have issued on February 7, 2018. However, on February 2, 2018, Sabal Trail filed with FERC a request for expedited issuance of its order on remand or, alternatively, temporary emergency certificates to permit continued operation of the pipeline absent a stay of the court’s mandate. On February 5, 2018, FERC issued its final supplemental environmental impact statement in compliance with the D.C. Circuit decision. In addition, on February 6, 2018, FERC filed a motion with the court requesting a 45-day stay of the mandate, and stated in its motion that it intends to issue the order on remand within 45 days. Sabal Trail filed a motion with the court requesting a 90-day stay of the mandate. The February 6, 2018 motions automatically stay the issuance of the court’s mandate until the later of seven days after the court denies the motions or the expiration of any stay granted by the court. Both motions are pending.

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 New York Stock Exchange (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
2017			
First Quarter	$ 0.68875	$ 47.49	$ 41.56
Second Quarter	0.70125	45.50	40.75
Third Quarter	0.71375	46.47	42.51
Fourth Quarter	0.72625	45.70	38.42
2016			
First Quarter	$ 0.63875	$ 50.48	$ 39.53
Second Quarter	0.65125	50.43	44.22
Third Quarter	0.66375	49.45	42.58
Fourth Quarter	0.67625	46.46	40.19

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

As of January 31, 2018, there were approximately 33 holders of record of our common units. A cash distribution to unitholders of $0.73875 per limited partner unit was declared on February 8, 2018 and is payable on February 28, 2018, which is a $0.0125 per limited partner unit increase over the cash distribution of $0.72625 per limited partner unit paid on November 29, 2017.

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Unit Performance Graph

The following graph reflects the comparative changes in the value from January 1, 2013 through December 31, 2017 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,				
	2013	2013	2014	2015	2016	2017
Spectra Energy Partners	$ 100.00	$152.86	$200.48	$176.38	$179.82	$165.46
S&P 500 Stock Index	100.00	132.39	150.51	152.59	170.84	208.14
Alerian MLP Index	100.00	127.58	133.71	90.13	106.63	99.68

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 our partnership agreement, to unitholders of record on the applicable record date.

On January 21, 2018, we entered into an Equity Restructuring Agreement with GP, LP, pursuant to which the incentive distribution rights and the 2% general partner interest in us held by GP, LP were converted into (i) 172,500,000 newly issued common units of Spectra Energy Partners and (ii) a non-economic general partner interest in us. Distributions will be made based on the terms of our limited partnership agreement in effect at the time a distribution is declared. Immediately following the execution of our Equity Restructuring Agreement, a new limited partnership agreement was entered into reflecting the new ownership structure.

Equity Compensation Plans

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

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Item 6. Selected Financial Data.

The following selected financial data should be read in conjunction with Part II. Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and Part II. Item 8. Financial Statements and Supplementary Data.

	Years Ended December 31,				
	2017	2016	2015	2014	2013
	(in millions, except per-unit amounts)				
Statements of Income					
Operating revenues	$1,950	$2,533	$2,455	$2,269	$1,965
Operating income	563	1,228	1,273	1,136	973
Net income attributable to noncontrolling interests	94	78	40	23	16
Net income attributable to controlling interests (a)	609	1,161	1,225	1,104	1,070
Limited Partner Unit Data					
Net income per limited partner unit—basic and diluted (b)	$0.77	$2.84	$3.30	$2.84	$4.25
Distributions paid per limited partner unit	2.83	2.63	2.43	2.245	2.02125

(a) Includes a $354 million benefit related to the elimination of accumulated deferred income tax liabilities in 2013.

(b) Earnings related to the U.S. Assets Dropdown for periods prior to November 1, 2013 were allocated entirely to the general partner in calculating net income per limited partner unit.

	December 31,				
	2017	2016	2015	2014	2013
	(in millions)				
Balance Sheets					
Total assets	$22,056	$21,606	$18,851	$17,778	$16,776
Total long-term debt	7,963	6,223	5,845	5,134	5,160

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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.

EXECUTIVE OVERVIEW

We reported net income attributable to controlling interests of $609 million in 2017 compared with $1,161 million in 2016 mainly due to the establishment of an estimated regulatory liability as a result of the U.S. tax reform legislation dated December 22, 2017, partially offset due to expansion projects and the valuation gain on the deconsolidation of Sabal Trail. Distributable cash flow was $1,392 million in 2017 compared with $1,187 million in 2016.

We increased our quarterly cash distribution each quarter in 2017, from $0.68875 per limited partner unit for the fourth quarter of 2016 which was paid in February 2017, to $0.73875 per unit for the fourth quarter of 2017 which is payable on February 28, 2018. Our expectation is that we will continue to increase our quarterly distribution by one and a quarter cents per unit each quarter through 2018. 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 $2.2 billion of capital and investment expenditures in 2017, including $2.0 billion of expansion and investment capital expenditures. We continue to foresee significant capital spending over the next several years, with approximately $1.6 billion planned for 2018, excluding contributions from noncontrolling interests. 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 2018. 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, 2017, we have access to a $2.5 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 and crude oil to premium markets. We will grow our business by way of organic growth, greenfield expansions and strategic acquisitions, with a steadfast 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 evolve, 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 gas-fired power generation and industrial markets, LNG exports from North America, and growth related to moving new sources of gas supplies to markets (including exports). With our advantage of providing first mile access from leading supply regions to the last mile of

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pipe to growing markets, we expect to continue expanding our assets and operations to meet the evolving needs of our customers.

Crude oil supply dynamics continue to evolve as North American oil production has shifted from growth to decline. In recent years, growing North American crude oil production has displaced imports from overseas and led to increased demand for crude oil transportation and logistics. Although depressed global crude oil prices resulted in declining North American oil production, we expect a return to attractive pricing and a growing North American production outlook. Thus, we remain confident about long-term growth in North American oil production and our ability to capture crude oil pipeline business.

Successful execution of our strategy will depend on maintaining our reputation and leadership as a safe and reliable operator and the effective execution of our capital projects. Continued growth and new opportunities will be determined by key factors, such as the continued growth and production of natural gas and crude oil within North America and our ability to provide creative solutions to meet the markets' evolving energy needs in both North America and beyond.

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 and/or natural gas, 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 demand would reduce the volume of natural gas transported, gathered and processed, and the volume of crude 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 contracts at expiration. Pipeline transmission customers continue to renew most contracts as they expire.

Our key natural gas markets—the northeastern, the southeastern and Gulf Coast regions of the 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 2020. This demand growth is primarily driven by the natural gas-fired electricity generation sector and Gulf Coast exports of natural gas and 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 still includes significant production from traditional sources in the Rocky Mountains, Midcontinent, and the U.S. Gulf Coast and is augmented by significant resource growth in Appalachia and West Texas. These supply shifts are shaping the growth strategies that we 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”. The construction of new pipelines has faced recent social and environmental activism and political pressures. 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 uncertainty on timing of permitting and execution of new projects.

Our key crude oil markets include the Rocky Mountain and Midwest states. Growth in our business is dependent on incremental crude oil supply from North American sources and the ability of that supply to compete with imported crude oil from overseas. Lower crude oil prices over the past two years have adversely affected the availability and cost-competitiveness of North American crude oil supply. This has not adversely affected our crude oil pipeline business, but sustained low oil prices could have a negative impact on our current business and associated growth opportunities although producers have adapted to and improved their competitiveness despite lower oil prices.

While the dramatic supply increase has been largely positive for midstream companies, lower price dynamics and shifting preferences on producing basins have resulted in other uneconomic impacts, which in the longer-term may impact some of our businesses and pipelines. Furthermore our storage business is adversely impacted by the contraction of 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, and while this has impacted our business, significant

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increases in demand on the Gulf Coast, particularly for exports should improve the value of our storage service. However, this may also expose our business to cyclical, economic and demand issues in other parts of the world.

Our businesses in the United States and Canada are subject to laws and regulations at the federal, state and provincial levels. Regulations applicable to the natural gas transmission, crude oil transportation and storage industries have a significant effect on the nature of the businesses and the manner in which they operate. Changes to regulations are ongoing and we cannot predict the future course of changes in the regulatory environment or the ultimate effect that any future changes will have on our businesses.

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, upgrade or replace pollution control equipment, and otherwise assure compliance.

PHMSA adopted pipeline safety legislation in 2011 and, more recently, in 2016 that, among other things, increased the penalties for safety violations, established additional safety requirements for newly constructed pipelines and required studies of safety issues that could result in the adoption of new regulatory requirements by PHMSA for existing pipelines, and empowered PHMSA to address imminent hazards by imposing emergency restrictions, prohibitions and safety measures on owners and operators of regulated pipeline facilities without prior notice or an opportunity for a hearing. PHMSA issued interim regulations in October 2016 to implement the agency’s expanded authority to address unsafe pipeline conditions or practices that pose an imminent hazard to life, property, or the environment.

Our interstate pipeline operations and our underground natural gas storage operations are subject to pipeline safety laws and regulations administered by PHMSA of the U.S. Department of Transportation. In December 2016, PHMSA issued final interim rules that impose new safety-related requirements on downhole facilities of new and existing underground natural gas storage facilities. 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, and design, operation and functional integrity of our underground storage wells. PHMSA indicated when it issued the interim final rule that the adoption of these safety standards for natural gas storage facilities represent a first step in a multi-phase process to enhance the safety of underground natural gas storage, with more standards likely forthcoming. Most recently, in response to a petition for reconsideration of the interim final rule received in January 2017, PHMSA published a notice in June 2017, advising that the agency intends to consider the issues raised by the petitioners in a final rule, which it currently expects to issue in 2018. At this time, we cannot predict the impact of any future regulatory actions in this area and can provide no assurance that our future costs to comply with existing or new standards relating to underground natural gas storage facilities will not have a material adverse effect on our business and operating results.

PHMSA is designing an Integrity Verification Process, in conjunction with their efforts to develop an Integrity Management Rule for Gas Pipelines, intended to create standards to verify maximum allowable operating pressure, and to improve and expand integrity management processes. Proposed rulemaking on these matters has not been finalized and there remains uncertainty as to how this process and rulemaking 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 light of the changing environmental and safety laws and regulations described above, we are evaluating efforts required to maintain compliance with such laws and regulations and, in addition, are assessing ways to improve overall system integrity, efficiency and reliability. The capital costs to effectively modernize our pipelines in this way will be substantial and will be incurred over several years.

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

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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. We have also experienced increased scrutiny placed on the permitting and construction of new projects from social and environmental activism, which can sometimes impact the timing of when constructions activities, and ultimate completion of a project, can occur relative to the expected timeline. Significant cost increases could negatively affect the returns ultimately earned on current and future expansions.

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

RESULTS OF OPERATIONS

	2017	2016	2015
	(in millions)		
Operating revenues	$1,950	$2,533	$2,455
Operating expenses	1,387	1,305	1,182
Operating income	563	1,228	1,273
Earnings from equity investments	307	127	167
Other income and expenses, net	117	126	76
Interest expense	265	224	239
Earnings before income taxes	722	1,257	1,277
Income tax expense	19	18	12
Net income	703	1,239	1,265
Net income—noncontrolling interests	94	78	40
Net income—controlling interests	$609	$1,161	$1,225

2017 Compared to 2016

Operating Revenues. The $583 million decrease was driven by:

- lower revenues due to the establishment of a regulatory liability as a result of the U.S. tax reform legislation dated December 22, 2017,
- lower recoveries of electric power and other costs passed through to gas transmission customers and
- lower storage revenues due to lower contract renewal rates, partially offset by
- increased revenues from expansion projects, primarily on Texas Eastern and Algonquin,
- higher revenues on Express pipeline due to higher average tariff rates and
- the Express Enhancement expansion project placed into service in October 2016.

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Operating Expenses. The $82 million increase was driven mainly by:

- increases in integrity and maintenance costs, and higher power and property tax expenses,
- higher costs related to expansion and
- an increase in merger-related severance costs, partially offset by
- lower pipeline inspection costs related to the 2016 Texas Eastern pipeline incident and
- a decrease in electric power and other costs passed through to gas transmission customers.

Earnings from Equity Investments. The $180 million increase was primarily attributable to the gain recognized as a result of the deconsolidation and re-measurement of Sabal Trail.

Other Income and Expenses, Net. The $9 million decrease was mainly attributable to lower allowance for funds used during construction (AFUDC) due to lower capital spending on expansion projects.

Interest Expense. The $41 million increase was driven mainly by higher average long-term debt balances and lower capitalized interest from expansion projects.

2016 Compared to 2015

Operating Revenues. The $78 million increase was driven by:

- revenues from expansion projects, primarily on Texas Eastern and Algonquin,
- storage revenues due to new contracts at higher rates, and
- higher crude oil transportation revenues due to the Express Enhancement expansion project placed into service in October 2016, partially offset by
- lower recoveries of electric power and other costs passed through to gas transmission customers,
- lower processing revenues primarily due to lower volumes,
- lower crude oil transportation revenues, as a result of lower volumes primarily on the Platte pipeline, substantially offset by increased tariff rates mainly on the Express pipeline, and
- lower natural gas transportation revenues mainly from interruptible transportation on Texas Eastern and M&N U.S., and short-term firm transportation on Algonquin.

Operating Expenses. The $123 million increase was driven mainly by:

- pipeline inspection and repair costs related to the Texas Eastern incident near Delmont, Pennsylvania,
- higher costs related to expansion, and
- higher property tax accruals due to the absence of a 2015 tax benefit, partially offset by
- lower electric power and other costs passed through to gas transmission customers,
- a prior year non-cash impairment charge on Ozark Gas Gathering,
- lower operating costs primarily due to employee benefit costs,
- lower maintenance costs,
- lower power costs due to lower usage on the Express and Platte pipelines, and
- lower project development costs.

Earnings from Equity Investments. The $40 million decrease was primarily attributable to the absence of equity earnings from Sand Hills and Southern Hills owned until October 2015.

Other Income and Expenses, Net. The $50 million increase was mainly attributable to higher AFUDC due to higher capital spending on expansion projects.

Interest Expense. The $15 million decrease was driven mainly by higher capitalized interest due to higher capital spending on expansion projects, partially offset by higher average long-term debt balances.

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Income Tax Expense. The $6 million increase mainly reflects an increase in Canadian earnings at Express-Platte.
For a more detailed discussion of earnings drivers, see the segment discussions that follow.

Segment Results

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.

Management evaluates segment performance based on 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. 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 provides transportation of crude oil for customers in central United States and Canada.

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

EBITDA by Business Segment

	2017	2016	2015
	(in millions)		
U.S. Transmission	1,199	1,639	$1,599
Liquids	259	237	283
Total reportable segment EBITDA	1,458	1,876	1,882
Other	(127)	(82)	(66)
Depreciation and amortization	346	314	295
Interest expense	265	224	239
Interest income and other	2	1	(5)
Earnings before income taxes	$722	$1,257	$1,277

The amounts discussed below are after eliminating intercompany transactions.

U.S. Transmission

	2017	2016	Increase (Decrease)	2015	Increase (Decrease)
	(in millions)				
Operating revenues	1,545	2,167	$ (622)	$2,087	$ 80
Operating expenses					
Operating, maintenance and other	769	779	$ (10)	680	99
Other income and expenses	423	251	$ 172	192	59
EBITDA	1,199	1,639	$ (440)	$1,599	$ 40

2017 Compared to 2016

Operating Revenues. The $622 million decrease was driven by:

- an $860 million decrease due to the establishment of a regulatory liability as a result of the U.S. tax reform legislation dated December 22, 2017. This charge has no immediate net impact to the rate base of the affected entities. In the event of a future rate case, and subject to further regulatory guidance, we anticipate that the charge may be required to be amortized over the remaining useful life of the affected assets and would be one of many factors to be considered in establishing go-forward rates.

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- a $10 million decrease in recoveries of electric power and other costs passed through to gas transmission customers and
- a $7 million decrease in storage revenues due to lower contract renewal rates, partially offset by
- a $256 million increase due to expansion projects, primarily on Algonquin and Texas Eastern.

Operating Expenses. The $10 million decrease was driven by:

- a $59 million decrease due to pipeline inspection costs related to the 2016 Texas Eastern pipeline incident,
- a $10 million decrease in electric power and other costs passed through to gas transmission customers and
- a $7 million decrease in property taxes, partially offset by
- a $37 million increase in costs related to expansion, and
- a $34 million increase primarily due to merger-related severance costs.

Other Income and Expenses. The $172 million increase was mainly due to a gain as a result of the deconsolidation and re-measurement of Sabal Trail and higher equity earnings resulting from Sabal Trail being placed in service on July 3, 2017.

2016 Compared to 2015

Operating Revenues. The $80 million increase was driven by:

- a $113 million increase due to expansion projects, primarily on Texas Eastern and Algonquin, and
- a $7 million increase in storage revenues due to new contracts at higher rates, partially offset by
- a $16 million decrease in recoveries of electric power and other costs passed through to gas transmission customers,
- a $15 million decrease in processing revenues primarily due to lower volumes, and
- a $9 million decrease in natural gas transportation revenues mainly from interruptible transportation on Texas Eastern and M&N U.S., and short-term firm transportation on Algonquin.

Operating Expenses. The $99 million increase was driven by:

- an $80 million increase due to pipeline inspection and repair costs related to the Texas Eastern incident near Delmont, Pennsylvania,
- a $47 million increase in costs related to expansion, and
- an $11 million increase in property tax accruals due to the absence of a 2015 tax benefit, partially offset by
- a $16 million decrease in electric power and other costs passed through to gas transmission customers,
- a $9 million decrease due to a non-cash impairment charge on Ozark Gas Gathering in 2015,
- an $8 million decrease in operating costs, and
- a $4 million decrease in project development costs.

Other Income and Expenses. The $59 million increase was mainly due to higher AFUDC resulting from higher capital spending on expansion projects.

Matters Affecting Future U.S. Transmission Results

We plan to grow our earnings 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

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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 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, a shift occurred to extraction of gas in richer, “wet” gas areas with higher natural gas liquids content which depressed activity in “dry” fields like the Fayetteville Shale formation where our Ozark assets are located. This, in turn, contributed to a resulting over-supply of pipeline take-away capacity in these areas. As the balance of supply and demand evolves, we expect activity in these areas to push prices higher. However, should supply and demand not come into balance, our businesses there may be subject to further 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 impairment, recognized in 2015, of our storage assets.

Our businesses in the United States are subject to laws and regulations on the federal and state levels. Regulations applicable to the natural gas transmission and storage industries have a significant effect on the nature of the businesses and the manner in which they operate. Changes to regulations are ongoing and we cannot predict the future course of changes in the regulatory environment or the ultimate effect that any future changes will have on our businesses.

FERC’s current policy 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 current tax allowance policy reflects 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 tax allowance policy applies to rates that we charge customers on our cost of service assets. The tax allowance policy does not affect market-based or negotiated rates that we charge customers.

On December 22, 2017, the US enacted the “Tax Cuts and Jobs Act” (“TCJA”). The changes in the TCJA are effective for taxation years beginning after December 31, 2017. While the changes are broad and complex, the most significant change is the reduction in the corporate federal income tax rate from 35% to 21%. Our regulated gas pipeline entities have recognized a regulatory liability of $860 million related to cost of service contracts where the tax rate will be adjusted in our rates at some time in the future. The regulatory liability represents amounts previously collected from utility customers for deferred taxes that may be refundable to such customers, generally through reductions in future rates.

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, upgrade or replace pollution control equipment, and otherwise assure compliance.

New legislation or regulations adopted by PHMSA may impose more stringent requirements applicable to integrity management programs and other pipeline safety aspects of our operations, which could cause us to incur increased capital costs, operational delays and costs of operations. PHMSA adopted pipeline safety legislation in 2011 and, more recently, in 2016 that, among other things, increased the penalties for safety violations, established additional safety requirements for newly constructed pipelines and required studies of safety issues that could result in the adoption of new regulatory requirements by PHMSA for existing pipelines, and empowered PHMSA to address imminent hazards by imposing emergency restrictions, prohibitions and safety measures on owners and operators of regulated pipeline facilities without prior notice or an opportunity for a hearing. PHMSA issued interim regulations in October 2016 to implement the agency's expanded authority to address unsafe pipeline conditions or practices that pose an imminent hazard to life, property, or the environment.

Our interstate pipeline operations and our underground natural gas storage operations are subject to pipeline safety regulations administered by 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, and design, operation and functional integrity of our underground storage wells. PHMSA indicated when it issued

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the interim final rule that the adoption of these safety standards for natural gas storage facilities represent a first step in a multi-phase process to enhance the safety of underground natural gas storage, with more standards likely forthcoming. Most recently, in response to a petition for reconsideration of the interim final rule received in January 2017, PHMSA published a notice in June 2017, advising that the agency intends to consider the issues raised by the petitioners in a final rule, which it currently expects to issue in 2018. At this time, we cannot predict the impact of any future regulatory actions in this area and can provide no assurance that our future costs to comply with existing or new standards relating to underground natural gas storage facilities will not have a material adverse effect on our business and operating results.

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. Proposed rulemaking on these matters has not been finalized and 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 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 light of the changing environmental and safety laws and regulations described above, we are evaluating efforts required to maintain compliance with such laws and regulations and, in addition, are assessing ways to improve overall system integrity, efficiency and reliability. The capital costs to effectively modernize our pipelines in this way will be substantial and will be incurred over several years.

Liquids

	2017	2016	Increase (Decrease)	2015	Increase (Decrease)
	(in millions)				
Operating revenues	$405	$366	$ 39	$368	$ (2)
Operating expenses					
Operating, maintenance and other	145	130	15	141	(11)
Other income and expenses	(1)	1	(2)	56	(55)
EBITDA	$259	$237	$ 22	$283	$ (46)
Express pipeline revenue receipts, MBbl/d (a)	262	241	21	239	2
Platte PADD II deliveries, MBbl/d	130	130	—	162	(32)

(a) Thousand barrels per day.

In October 2015, Spectra Energy acquired our 33.3% ownership interests in Sand Hills and Southern Hills. Results presented herein include Sand Hills and Southern Hills through October 30, 2015, the date of Spectra Energy's acquisition.

2017 Compared to 2016

Operating Revenues. The $39 million increase in operating revenues was driven by:

- an increase in transportation revenues due to the Express Enhancement expansion project placed into service in October 2016 and higher average tariff rates on the Express pipeline, partially offset by
- lower average tariff rates on the Platte pipeline due to discounts on domestic volumes.

Operating Expenses. The $15 million increase in operating expenses was driven by:

- an increase in integrity and maintenance costs, and higher power and property tax expenses.

2016 Compared to 2015

Operating Revenues. The $2 million decrease in operating revenues was driven by:

-

a $10 million decrease in crude oil transportation revenues, as a result of lower volumes primarily on the Platte pipeline, substantially offset by increased tariff rates mainly on the Express pipeline, partially offset by

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- a $7 million increase in crude oil transportation revenues due to the Express Enhancement expansion project placed into service in October 2016.

Operating Expenses. The $11 million decrease in operating expenses was driven by:

- a $6 million decrease in maintenance costs, and
- a $5 million decrease in power costs due to lower usage in 2016 on the Express and Platte pipelines.

Other Income and Expenses. The $55 million decrease was primarily due to the absence of equity earnings from Sand Hills and Southern Hills owned until October 30, 2015.

Matters Affecting Future Liquids Results

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 crude oil and continued access to attractive markets.

See Matters Affecting Future U.S. Transmission Results for discussions of pipeline safety, regulatory certainty and the PHMSA, which are also applicable to the Liquids segment.

Other

	2017	2016	Increase (Decrease)	2015	Increase (Decrease)
	(in millions)				
Operating expenses	(127)	(82)	$ 45	$(66)	$ 16
EBITDA	$(127)	$(82)	$ (45)	$(66)	$ (16)

2017 Compared to 2016

Operating Expenses. The $45 million increase reflects $38 million from merger-related severance costs, with the remainder related to higher allocated shared service and governance costs.

2016 Compared to 2015

Operating Expenses. The $16 million increase was driven by higher allocated governance costs.

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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
- earnings from equity investments,
- interest expense,
- equity AFUDC,
- net cash paid for income taxes,
- distributions to noncontrolling interests, and
- maintenance capital expenditures.

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.

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 in the United States (U.S. GAAP). 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.

We use earnings from continuing operations before interest, income taxes, and depreciation and amortization (EBITDA), a non-GAAP financial measure, and the most directly comparable GAAP measure for EBITDA is net income.

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Reconciliation of Net Income to Non-GAAP “Distributable Cash Flow”

	2017	2016	2015
	(in millions)		
Net Income	$703	$1,239	$1,265
Add:			
Interest expense	265	224	239
Income tax expense	19	18	12
Depreciation and amortization	346	314	295
Foreign currency (gain) loss	(1)	1	6
Less:			
Interest income	1	2	1
EBITDA	1,331	1,794	1,816
Add:			
Earnings from equity investments	(307)	(127)	(167)
Distributions from equity investments (a)	185	160	207
Non-cash impact of US tax reform	860	—	—
Non-cash impairment at Ozark Gas Gathering	—	—	9
Other	10	13	12
Less:			
Interest expense	265	224	239
Equity AFUDC	115	121	76
Net cash paid for income taxes	15	10	12
Distributions to noncontrolling interests	49	30	31
Maintenance capital expenditures	243	268	314
Distributable Cash Flow	$1,392	$1,187	$1,205

(a) Excludes $403 million of distributions from equity investments for the 2015 period, $396 million of which relates to the Gulfstream debt issuance. See Note 4 of Notes to Consolidated Financial Statements for further discussion.

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CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Our consolidated financial statements are prepared in accordance with U.S. GAAP, which require management to make estimates, judgments and assumptions that affect the amounts reported in our consolidated financial statements and accompanying notes. In making judgments and estimates, management relies on external information and observable conditions, where possible, supplemented by internal analysis as required. We believe our most critical accounting policies and estimates discussed below have an impact across the various segments of our business.

Regulation

Certain of our businesses are subject to regulation by various authorities, including but not limited to, the NEB and the FERC. Regulatory bodies exercise statutory authority over matters such as construction, rates and ratemaking and agreements with customers. To recognize the economic effects of the actions of the regulator, the timing of recognition of certain revenues and expenses in these operations may differ from that otherwise expected under U.S. GAAP for non-rate-regulated entities. Key determinants in the ratemaking process are:

- Costs of providing service, including depreciation expense;
- Allowed rate of return, including the equity component of the capital structure and related income taxes;
- Contract and volume throughput assumptions.

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.

Total regulatory assets were $220 million as of December 31, 2017 and $376 million as of December 31, 2016. Total regulatory liabilities were $896 million as of December 31, 2017 and $61 million as of December 31, 2016.

Goodwill Impairment

We assess our goodwill for impairment at least annually unless events or changes in circumstances indicate that it is more likely than not that the fair value of a reporting unit is below its carrying value. For the purposes of impairment testing, reporting units are identified as business operations within an operating segment. We have the option to first assess qualitative factors to determine whether it is necessary to perform the quantitative goodwill impairment test. The quantitative goodwill impairment test involves determining the fair value of our reporting units inclusive of goodwill and comparing those values to the carrying value of each reporting unit. If the carrying value of a reporting unit, including allocated goodwill, exceeds its fair value, goodwill impairment is measured as the excess of the carrying amount of the reporting unit’s allocated goodwill over the fair value of the goodwill based on the fair value of the reporting unit’s assets and liabilities.

We performed either a quantitative assessment or a qualitative assessment for each 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, 2017 (our annual testing date). Based on that assessment, we determined that this condition, for each reporting unit, does not exist. No triggering events occurred during the period from April 1, 2017 through December 31, 2017 that warranted re-testing for goodwill impairment.

We had goodwill balances of $2,957 million at December 31, 2017 and $3,234 million at December 31, 2016. The decrease in goodwill in 2017 was the result of the deconsolidation of Sabal Trail, partially offset by foreign currency translation. See Note 9 of Notes to Consolidated Financial Statements for further discussion.

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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 revenues are immaterial.

LIQUIDITY AND CAPITAL RESOURCES

Known Trends and Uncertainties

As of December 31, 2017, we had negative working capital of $544 million. This balance includes current maturities of long-term debt of $500 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 2018. We have access to a revolving credit facility, with available capacity of $246 million at December 31, 2017. 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. 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 investments 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 investments. The amount of cash distributed to us by our equity investments and the amount of cash we may be required to fund, is determined by our equity investments based on their operating cash flows and other factors as determined by their management. While we participate on the management committees of these equity investments, determination of the amount of distributions and contributions, if any, are not within our control. We received total distributions from equity investments of $185 million in 2017, $160 million in 2016 and $610 million in 2015. See Part I. 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,		
	2017	2016	2015
	(in millions)		
Net cash provided by (used in):			
Operating activities	$1,610	$1,462	$1,522
Investing activities	(2,289)	(2,754)	(1,830)
Financing activities	570	1,340	336
Net increase (decrease) in cash and cash equivalents	(109)	48	28
Cash and cash equivalents at beginning of the period	216	168	140
Cash and cash equivalents at end of the period	$107	$216	$168

Operating Cash Flows

Net cash provided by operating activities increased $148 million to $1,610 million in 2017 compared to 2016. This increase was driven primarily by higher earnings after adjusting for non-cash items, partially offset by changes in working capital.

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Net cash provided by operating activities decreased $60 million to $1,462 million in 2016 compared to 2015. This decrease was driven primarily by the absence of distributions from Sand Hills and Southern Hills owned until October 2015.

Investing Cash Flows

Net cash flows used in investing activities decreased $465 million to $2,289 million in 2017 compared to 2016. This decrease was driven mainly by:

- a $446 million decrease in capital and investment expenditures, and
- a $148 million distribution of debt proceeds back to Gulfstream for payment of its matured debt in 2016, partially offset by
- a $86 million increase in investments in and loans to unconsolidated affiliates, and
- a $67 million cash outflow as a result of Sabal Trail deconsolidation.

Net cash flows used in investing activities increased $924 million to $2,754 million in 2016 compared to 2015. This increase was driven mainly by a $578 million net increase in capital and investment expenditures.

Capital and Investment Expenditures by Business Segment

	Years Ended December 31,		
	2017	2016	2015
	(in millions)		
U.S. Transmission	$2,204	$2,514	$1,952
Liquids	21	71	55
Total consolidated	$2,225	$2,585	$2,007

Capital and investment expenditures for 2017 totaled $2,225 million and included $1,982 million for expansion projects, and $243 million for maintenance and other projects.

We project 2018 capital and investment expenditures of approximately $1.6 billion, including $1.4 billion of expansion capital expenditures and $0.2 billion for maintenance and upgrades of existing plants, pipelines and infrastructure to serve growth. These projections exclude contributions from noncontrolling interests. Expansion capital expenditures may vary significantly based on investment opportunities.

In October 2015, Spectra Energy acquired our 33.3% ownership interests in Sand Hills and Southern Hills. In consideration for this transaction, we retired 21,560,000 of our common units and 440,000 of our general partner units beneficially held by Spectra Energy resulting in a reduction of any associated distributions ultimately payable to Spectra Energy. As a result of the transaction, there is a reduction in the aggregate quarterly distributions, if any, to the General Partner, (as holder of incentive distribution rights), by $4 million per quarter for a period of 12 consecutive quarters ending on September 30, 2018. See Note 3 of Notes to Consolidated Financial Statements for further discussion.

In November 2015, we acquired the remaining 0.1% ownership interest in SESH from Spectra Energy. Total consideration was 17,114 newly issued common units. In addition, we issued 342 general partner units to our General Partner in exchange for the same amount of common units in order to maintain the General Partner's 2% general partner interest. This was the last of three planned transactions related to the U.S. Assets Dropdown. See Note 3 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 2017, including:

- Algonquin Incremental Market (AIM) - A 342 million cubic feet per day (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 markets in the northeast. 72% of the project was placed in-service in the fourth quarter of 2016 and the remainder was placed into service in the first quarter of 2017.
- Access South / Adair Southwest / Lebanon Extension - This project combined is designed to attach emerging Ohio Marcellus and Utica natural gas supplies to new markets in the Midwest and Southeast along Texas Eastern's existing footprint totaling 622 MMcf/d of gas deliveries to customers. The project was placed into service in the fourth quarter of 2017.
- 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 reverse-compression capability at six compressor stations to provide up to 650 MMcf/d. This project was executed in two phases. Phase 1 was placed into service in the fourth quarter of 2016, and provided north to south compression at five stations. Phase 2 was placed into service in the third quarter of 2017 and provided north to south compression at a sixth station, added a new compression unit at one existing compressor station and constructed one new compressor station.
- Sabal Trail - 1,100 MMcf/d of new capacity to access onshore shale gas supplies. Facilities include a new approximately 515-mile pipeline, laterals and various compressor stations. This project was placed into service in the third quarter of 2017.

In addition to the remaining work mentioned above, significant 2018 expansion projects expenditures are also expected to include:

- Atlantic Bridge - This project is an expansion of the Algonquin system to transport 133 MMcf/d of natural gas to the New England Region. Lift and relay of pipeline, compressor stations and meter stations will be required. The Connecticut portion of the project was placed into service in the fourth quarter of 2017. The remainder of the project is expected to be in-service during the fourth quarter of 2018.
- PennEast - A 1,100 MMcf/d 36-inch pipeline with scalable facilities and two compressor stations that runs 118 miles from Northeast, Pennsylvania production to Texas Eastern and Algonquin- Lambertville and Transco-Woodbridge. The project is expected to be in-service in 2019.
- NEXUS - Greenfield path to transport 1.5 Bcf/d from SEP's Texas Eastern pipeline to the Union Gas Dawn hub in Ontario, Canada. The facilities will consist of approximately 255 miles of 36-inch pipeline across northern Ohio to the Detroit, Michigan area, the addition of four new compressor stations totaling 130,000 horsepower, and six meter stations. The project is expected to be in-service during the third quarter of 2018.
- South Texas Expansion - The project will expand the Texas Eastern facilities in order to deliver 400 MMcf/d gas supplies from east of Vidor, Texas to high demand markets in south Texas with a single delivery point in Petronila. The project is expected to be in-service during the second half of 2018.
- Stratton Ridge - This project will deliver 322 MMcf/d of gas from Stratton Ridge Storage to Freeport LNG Train 3. The project scope also consists of additional compression, piping, and metering and regulation work on the Angleton Compressor Station and Angleton Line, as well as work on the Brazoria Interconnector Gas (B.I.G) pipeline and Mont Belvieu, Joaquin, Huntsville, Hempstead, and Provident City Station Sites. The project is expected to be in-service during the first half of 2019.
- Texas Eastern Appalachian Lease (TEAL) - This project is designed to create a gas path from the Texas Eastern mainline system in Monroe County, Ohio, utilizing the Ohio Pipeline Energy Network (OPEN) pipeline, to deliver gas northward to NEXUS at Kensington, Ohio. The pipeline portion of the project is due to go in service during the second half of 2018, and the compressor station portion is due to go in service during the first half of 2019.

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Financing Cash Flows

Net cash provided by financing activities decreased $770 million to $570 million in 2017 compared to 2016. This decrease was driven mainly by:

- a $906 million decrease in proceeds from issuances of units, and
- a $130 million decrease in proceeds from issuance of long-term debt, and
- a $542 million increase in repayments for the redemption of long-term debt, and
- a $325 million decrease in contributions from noncontrolling interests, and
- a $166 million increase in distributions to partners, partially offset by
- $1,408 million of net issuances of commercial paper in 2017, compared to $98 million of net issuances in 2016.

Net cash provided by financing activities totaled $1,340 million in 2016 compared to $336 million used in financing activities in 2015. This $1,004 million change was driven mainly by:

- $98 million of net issuances of commercial paper in 2016, compared to $431 million of net redemptions in 2015,
- a $522 million increase in proceeds from issuances of units, and
- a $495 million increase in contributions from noncontrolling interests, partially offset by
- $520 million in net issuances of long-term debt in 2016, compared to $962 million in net issuances of long-term debt in 2015, and
- a $100 million increase in distributions to partners.

Significant Financing Activities—2017

Debt Issuances. On June 7, 2017, we issued $400 million of variable-rate senior unsecured notes due in 2020. Net proceeds from the offering were used to fully repay and terminate the variable-rate senior unsecured term loan due in November 2018.

Common Unit Issuances. In 2017, we issued 4.0 million common units to the public under our at-the-market program and approximately 81,000 general partner units to our general partner. Total net proceeds were $174 million, including approximately $3 million of proceeds from our general partner. The net proceeds were used for general partnership purposes, which may have included debt repayment, capital expenditures and/or additions to working capital.

Significant Financing Activities—2016

Debt Issuances. On October 17, 2016, we issued $800 million aggregate principal amount of senior unsecured notes, comprised of $600 million of 3.375% senior notes due in 2026 and $200 million of 4.50% senior notes due in 2045. The new 2045 notes are an additional issuance of our 4.50% senior notes issued in March 2015. Net proceeds from the offering were used to repay a portion of outstanding commercial paper, to fund capital expenditures and for general partnership purposes.

Common Unit Issuances. In April 2016, we issued 10.4 million common units and 0.2 million general partner units to our general partner in a private placement transaction. Total net proceeds were approximately $489 million. We used the proceeds from this purchase for general partnership purposes, including the funding of our current expansion capital plan.

In 2016, we issued 12.8 million common units to the public under our at-the-market program and approximately 262,000 general partner units to our general partner. Total net proceeds were $591 million, including approximately $12 million of proceeds from our general partner. The net proceeds were used for general partnership purposes, which may have included debt repayment, capital expenditures and/or additions to working capital.

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Significant Financing Activities—2015

Debt Issuances. On March 12, 2015, we issued $1.0 billion aggregate principal amount of senior unsecured notes, comprised of $500 million of 3.50% senior notes due in 2025 and $500 million of 4.50% senior notes due in 2045. Net proceeds from the offering were used to repay a portion of outstanding commercial paper, to fund capital expenditures and for general partnership purposes.

Common Unit Issuances. On November 4, 2015, we issued 17,114 common units in connection with the U.S. Assets Dropdown, valued at $1 million. In addition, we issued 342 general partner units to our general partner in exchange for the same amount of common units in order to maintain our general partner's 2% general partner interest. See Note 2 of Notes to Consolidated Financial Statements for further discussion.

In March 2015, we entered into an equity distribution agreement under which we may sell and issue common units up to an aggregate offering price of $500 million, and in December 2015 we replaced the equity distribution agreement. The terms of this new equity distribution agreement are substantially similar to those in our previous agreements and allow us to sell and issue up to an aggregate offering price of $1 billion of common units. 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 12 million common units to the public in 2015 under our at-the-market program, and approximately 245,000 general partner units to our general partner. Total net proceeds were $557 million, including approximately $11 million of proceeds from our general partner.

Available Credit Facility and Restrictive Debt Covenants

	Maturity Dates(a)	Total Facility	Draws (b)	Available
		(in millions)		
Spectra Energy Partners, LP	2022	$2,500	$2,254	$ 246

(a) Includes $336 million of commitments that expire in 2021.

(b) Includes facility draws and commercial paper issuances that are back-stopped by the credit facility.

Our credit facility agreements and term debt indentures include common events of default and covenant provisions, including a financial covenant, whereby accelerated repayment and/or termination of the agreements may result if we were to default on payment or violate certain covenants. As of December 31, 2017, we were in compliance with the covenants.

Cash Distributions. Our 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.

We increased the quarterly cash distributions each quarter of 2017 from $0.68875 per limited partner unit for the fourth quarter of 2016 to $0.73875 per limited partner unit for the fourth quarter of 2017. The cash distribution for the fourth quarter of 2017 was declared on February 8, 2018 and is payable on February 28, 2018.

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.

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Other Financing Matters. We have an effective shelf registration statement on file with the SEC to register the issuance of unlimited amounts of limited partner common units and various debt securities and another registration statement on file with the SEC to register the issuance of $1 billion, in the aggregate, of limited partner common units and various debt securities over time. This registration statement has $186 million available as of December 31, 2017.

Off Balance Sheet Arrangements

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

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

We do not have any off-balance sheet financing entities or structures, except for normal operating lease arrangements, guarantee arrangements and financings entered into by our 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, 2017 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 2018.

Contractual Obligations as of December 31, 2017

	Payments Due by Period				
	Total	2018	2019 & 2020	2021 & 2022	2023 & Beyond
	(in millions)				
Long-term debt (a)(b)	$11,419	$760	$1,295	$3,418	$5,946
Operating leases (b)	208	15	37	36	120
Purchase obligations (c)	363	18	54	49	242
Total contractual cash obligations	$11,990	$793	$1,386	$3,503	$6,308

(a) See Note 14 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 18 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 policy to monitor and manage these market risks. While our management team is responsible for the day to day governance and compliance for us, the implementation of our risk policies is delegated to an Enbridge committee. The responsibilities of this committee include monitoring our interest rate risk and credit risk, including monitoring exposure limits to ensure compliance with our policy.

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-

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notice services. Our principal customers for natural gas transmission and storage services are industrial end-users, marketers, exploration and production companies, LDCs and utilities located throughout the United States and Canada. 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 Enbridge), 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.

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 also monitor our debt portfolio mix of fixed and variable rate debt instruments to manage interest rate risk exposure. We primarily use qualifying derivative instruments to manage interest rate risk. See also Notes 2, 15 and 16 of Notes to Consolidated Financial Statements.

As of December 31, 2017, 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 $900 million to hedge against changes in the fair value of our fixed-rate debt that arise as a result of changes in market interest rates. These swaps also allow us to transform a portion of the underlying interest payments related to our long-term fixed-rate debt securities into variable-rate interest payments in order to achieve our desired mix of fixed and variable-rate debt.

As of December 31, 2017, our earnings and cash flows are also exposed to variability in longer term interest rates ahead of anticipated fixed rate term debt issuances. Forward starting interest rate swaps are used to hedge against the effect of future interest rate movements. We have assumed a program to mitigate our exposure to long-term interest rate variability on select forecast term debt issuances via execution of floating to fixed interest rate swaps with an average swap rate of 2.48%. The total notional amount is $1.6 billion. The forecasted fixed rate term debt issuances are planned for 2018 and 2020.

Based on a sensitivity analysis as of December 31, 2017, it was estimated that if short-term interest rates average 100 basis points higher (lower) in 2018 than in 2017, interest expense, net of offsetting interest income, would fluctuate by $35 million before tax. Comparatively, based on a sensitivity analysis as of December 31, 2016, had short-term interest rates averaged 100 basis points higher (lower) in 2017 than in 2016, it was estimated that interest expense, net of offsetting interest income, would have fluctuated by approximately $17 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, 2017 and 2016.

Commodity Price Risk

Our earnings and cash flows are exposed to changes in commodity prices as a result of our ownership interests in certain assets. These commodities include natural gas, crude oil, power and NGL. We employ financial derivative instruments to fix a portion of the variable price exposures that arise from physical transactions involving these commodities. We use non-qualifying derivative instruments to manage commodity price risk. In July 2017, we entered into a power swap to fix a portion of the variable price exposure for power costs in our Express Canada operations until 2020.

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OTHER ISSUES

For information on other issues, see Notes 6 and 18 of Notes to Consolidated Financial Statements.

New Accounting Pronouncements

See Note 2 of Notes to Consolidated Financial Statements for discussion.

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

See Part II. Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations — Quantitative and Qualitative Disclosures About Market Risk for 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 adequate internal control over financial reporting, as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended (Exchange Act). Our internal control over financial reporting is a process 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 Principal Executive Officer and Principal Financial Officer, has conducted an evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2017 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 as of December 31, 2017.

PricewaterhouseCoopers LLP, an independent registered public accounting firm, audited the effectiveness of our internal control over financial reporting as of December 31, 2017 and issued an unqualified opinion thereon as stated in their report, which appears under Item 8.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Unitholders of Spectra Energy Partners, LP:

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheet of Spectra Energy Partners, LP and its subsidiaries (together, the “Partnership”) as of December 31, 2017 and the related consolidated statements of income, of comprehensive income, of equity and of cash flows for the year then ended, including the related notes (collectively referred to as the “consolidated financial statements”). We also have audited the Partnership’s internal control over financial reporting as of December 31, 2017, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (“COSO”).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Partnership as of December 31, 2017 and the results of their operations and their cash flows for the year then ended in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on criteria established in Internal Control - Integrated Framework (2013) issued by the COSO.

Basis for Opinions

The Partnership’s management is responsible for these consolidated financial statements, 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 opinions on the Partnership’s consolidated financial statements and on the Partnership’s internal control over financial reporting based on our audit. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (“PCAOB”) and are required to be independent with respect to the Partnership in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audit of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audit also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. 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 audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

Definition and Limitations of Internal Control over Financial Reporting

A company’s internal control over financial reporting is a process 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. A company’s internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) 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 (iii) provide reasonable

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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 its 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 the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP

Houston, Texas
February 15, 2018

We have served as the Partnership's auditor since 2017.

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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 sheet of Spectra Energy Partners, LP and subsidiaries (the "Partnership") as of December 31, 2016, and the related consolidated statements of operations, comprehensive income, cash flows and equity for each of the two years in the period ended December 31, 2016. The Partnership’s management is responsible for these financial statements. Our responsibility is to express an opinion on these financial statements 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. 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. We believe that our audits provide a reasonable basis for our opinion.

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, 2016, and the results of their operations and their cash flows for each of the two years in the period ended December 31, 2016, in conformity with accounting principles generally accepted in the United States of America.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
February 24, 2017

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

	Years Ended December 31,		
	2017	2016	2015
Operating revenues			
Transportation of natural gas	$1,331	$1,951	$1,858
Transportation of crude oil	394	359	357
Storage of natural gas and other	225	223	240
Total operating revenues	1,950	2,533	2,455
Operating expenses			
Operating, maintenance and other	844	822	750
Depreciation and amortization	346	314	295
Property and other taxes	197	169	137
Total operating expenses	1,387	1,305	1,182
Operating income	563	1,228	1,273
Other income and expenses			
Earnings from equity investments	307	127	167
Other income and expenses, net	117	126	76
Total other income and expenses	424	253	243
Interest expense	265	224	239
Earnings before income taxes	722	1,257	1,277
Income tax expense	19	18	12
Net income	703	1,239	1,265
Net income attributable to noncontrolling interests	94	78	40
Net income attributable to controlling interests	$609	$1,161	$1,225
Net income attributable to controlling interests	$609	$1,161	$1,225
Net income attributable to general partner	369	311	249
Net income attributable to limited partners	$240	$850	$976
Weighted average limited partners units outstanding — basic and diluted	310	299	296
Net income per limited partner unit — basic and diluted	$0.77	$2.84	$3.30
Distributions paid per limited partner unit	$2.83	$2.63	$2.43

The accompanying notes are an integral part of these consolidated financial statements.

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

	Years Ended December 31,		
	2017	2016	2015
Net income	$703	$1,239	$1,265
Other comprehensive income (loss):			
Foreign currency translation adjustments	15	5	(29)
Change in unrealized loss on cash flow hedges	(3)	—	—
Reclassification to net income of gain on cash flow hedges	—	—	(1)
Other comprehensive income (loss)	12	5	(30)
Comprehensive income	715	1,244	1,235
Comprehensive income attributable to noncontrolling interests	94	78	40
Comprehensive income attributable to controlling interests	$621	$1,166	$1,195

The accompanying notes are an integral part of these consolidated financial statements.

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

	December 31, 2017	2016
ASSETS		
Current Assets		
Cash and cash equivalents	$107	$216
Receivables (net of allowance for doubtful accounts of $10 and $6 at December 31, 2017 and 2016, respectively)	372	380
Inventory	40	40
Other assets, net	42	24
Total current assets	561	660
Investments in and loans to unconsolidated affiliates	3,302	1,127
Goodwill	2,957	3,234
Property, plant and equipment, net	14,899	16,092
Regulatory and other assets	337	493
Total Assets	$22,056	$21,606
LIABILITIES AND EQUITY		
Current Liabilities		
Accounts payable	$259	$441
Commercial paper	—	574
Taxes payable	84	76
Interest payable	68	79
Current portion of long-term debt	500	416
Other	194	193
Total current liabilities	1,105	1,779
Long-term debt	7,963	6,223
Deferred income taxes	46	42
Regulatory and other liabilities	1,041	158
Total Liabilities	10,155	8,202
Commitments and Contingencies		
Partners' Capital		
Common units (312.4 and 308.4 units issued and outstanding at December 31, 2017 and 2016, respectively)	11,183	11,650
General partner units (6.4 and 6.3 units issued and outstanding at December 31, 2017 and 2016, respectively)	386	452
Accumulated other comprehensive loss	(33)	(45)
Total partners' capital	11,536	12,057
Noncontrolling interests	365	1,347
Total Equity	11,901	13,404
Total Liabilities and Equity	$22,056	$21,606

The accompanying notes are an integral part of these consolidated financial statements.

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

	Years Ended December 31,		
	2017	2016	2015
OPERATING ACTIVITIES			
Net income	$703	$1,239	$1,265
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	338	320	304
Deferred income tax expense	3	4	3
Earnings from equity investments	(307)	(127)	(167)
Distributions from equity investments	152	110	160
Regulatory liability - deferred income taxes	860	—	—
Change in operating assets and liabilities	(139)	(84)	(43)
Net cash provided by operating activities	1,610	1,462	1,522
INVESTING ACTIVITIES			
Capital expenditures	(1,888)	(2,334)	(1,883)
Investments in and loans to unconsolidated affiliates	(337)	(251)	(124)
Additions to intangible assets	(40)	(80)	—
Distributions from equity investments	33	50	450
Distributions to equity investment	—	(148)	(248)
Purchases of held-to-maturity securities	(20)	(39)	(44)
Proceeds from sales and maturities of held-to-maturity securities	20	39	44
Purchases of available-for-sale securities	(69)	(714)	(95)
Proceeds from sales and maturities of available-for-sale securities	76	715	84
Net cash outflow from deconsolidation of subsidiary	(67)	—	—
Other changes in restricted funds	1	9	(14)
Other	2	(1)	—
Net cash used in investing activities	(2,289)	(2,754)	(1,830)
FINANCING ACTIVITIES			
Proceeds from issuance of long-term debt	670	800	994
Payments for the redemption of long-term debt	(822)	(280)	(32)
Net change in credit facility draws	1,408	98	(431)
Distributions to noncontrolling interests	(49)	(30)	(31)
Contributions from noncontrolling interests	418	743	248
Proceeds from the issuances of units	174	1,080	558
Distributions to partners	(1,227)	(1,061)	(961)
Other	(2)	(10)	(9)
Net cash provided by financing activities	570	1,340	336
Net increase (decrease) in cash and cash equivalents	(109)	48	28
Cash and cash equivalents at beginning of the period	216	168	140
Cash and cash equivalents at end of the period	$107	$216	$168
Supplemental Disclosures			
Cash paid for interest, net of amount capitalized	$267	$209	$218
Cash paid for income taxes	15	10	12

Property, plant and equipment noncash accruals	54	247	140

The accompanying notes are an integral part of these 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, 2014	10,474	284	(20)	268	11,006
Net income	976	249	—	40	1,265
Other comprehensive loss, net of tax	—	—	(30)	—	(30)
Retirement of units	(794)	(15)	—	—	(809)
Consideration over net disposed assets	51	1	—	—	52
Attributed deferred tax benefit	—	39	—	8	47
Issuances of units	547	11	—	—	558
Distributions to partners	(728)	(233)	—	—	(961)
Contributions from noncontrolling interests	—	—	—	248	248
Distributions to noncontrolling interests	—	—	—	(31)	(31)
Other, net	1	—	—	—	1
December 31, 2015	10,527	336	(50)	533	11,346
Net income	850	311	—	78	1,239
Other comprehensive income, net of tax	—	—	5	—	5
Attributed deferred tax benefit	—	59	—	23	82
Issuances of units	1,058	22	—	—	1,080
Distributions to partners	(785)	(276)	—	—	(1,061)
Contributions from noncontrolling interests	—	—	—	743	743
Distributions to noncontrolling interests	—	—	—	(30)	(30)
December 31, 2016	$11,650	$452	$ (45)	$ 1,347	$13,404
Net income	240	369	—	94	703
Other comprehensive income	—	—	12	—	12
Attributed deferred tax benefit	—	(89)	—	(5)	(94)
Issuance of units	171	3	—	—	174
Distributions to partners	(878)	(349)	—	—	(1,227)
Contributions from noncontrolling interests	—	—	—	418	418
Distributions to noncontrolling interests	—	—	—	(49)	(49)
Sabal Trail deconsolidation	—	—	—	(1,440)	(1,440)
December 31, 2017	11,183	386	(33)	365	11,901

The accompanying notes are an integral part of these consolidated financial statements.

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SPECTRA ENERGY PARTNERS, LP
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1. Business Overview

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 investments, is engaged in the transmission, storage and gathering of natural gas and the transportation and storage of crude oil through interstate pipeline systems. We are a Delaware master limited partnership (MLP).

On February 27, 2017, Enbridge Inc. (Enbridge) and Spectra Energy Corp (Spectra Energy) completed a merger transaction (the Merger) resulting in Spectra Energy being a wholly-owned subsidiary of Enbridge. As a result of the Merger, we became an indirect subsidiary of Enbridge through Enbridge's ownership of Spectra Energy.

As of December 31, 2017, Enbridge and its subsidiaries collectively owned a 74% ownership interest in us, with the remaining 26% publicly owned.

2. Significant Accounting Policies

These consolidated financial statements are prepared in accordance with generally accepted accounting principles in the United States of America (U.S. GAAP).

Basis of Presentation. The preparation of financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, as well as the disclosure of contingent assets and liabilities in the consolidated financial statements. We regularly evaluate these estimates utilizing historical experience, consultation with experts and other methods we consider reasonable in the circumstances. Nevertheless, actual results may differ from these estimates. We record the effect of any revisions to these estimates in our consolidated financial statements in the period in which the facts that give rise to the revision become known.

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.

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.

Regulation. Our businesses are subject to regulation by various authorities including, but not limited to, the Federal Energy Regulatory Commission (FERC) and the National Energy Board (NEB). Regulatory bodies exercise statutory authority over matters such as construction, rates and ratemaking and agreements with customers. To recognize the economic effects of the actions of the regulator, the timing of recognition of certain revenues and expenses in these operations may differ from that otherwise expected under U.S. GAAP for non rate-regulated entities.

Regulatory assets represent amounts that are expected to be recovered from customers in future periods through rates. Regulatory liabilities represent amounts that are expected to be refunded to customers in future periods through rates. These regulatory assets and liabilities are mostly classified in the Consolidated Balance Sheets as Regulatory and other assets and Regulatory and other liabilities. Regulatory assets are assessed for impairment if we identify an event indicative of possible impairment. The recognition of regulatory assets and liabilities is based on the actions, or expected future actions, of the regulator. To the extent that the regulator’s actions differ from our expectations, the timing and amount of recovery or settlement of regulatory balances could

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differ from those recorded. In the absence of rate regulation, we would generally not recognize regulatory assets or liabilities and the income impact would be recorded in the period the expenses are incurred or revenues are earned.

Foreign Currency Translation. The Canadian dollar has been determined to be the functional currency of the Canadian portion of the Express-Platte pipeline system (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 Income (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 gain totaled $1 million in 2017, and losses totaled $1 million, and $6 million in 2016 and 2015 respectively and are included in Other Income and Expenses, Net on the Consolidated Statements of Income.

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 revenues are immaterial. There was one customer, National Grid PLC, in the U.S. Transmission segment accounting for $244 million, or approximately 13%, of consolidated revenues during 2017. There were no customers accounting for 10% or more of consolidated revenues during 2016 or 2015. 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 Equity Used During Construction (AFUDC). AFUDC, which represents the estimated debt and equity costs of capital funds necessary to finance the construction and expansion of certain new regulated facilities, consists of two components, an equity component and an interest expense component. After construction is completed, we are permitted to recover these costs through inclusion in the rate base and in the depreciation provision. AFUDC is capitalized as a component of Property, plant and equipment - net in the Consolidated Balance Sheets, with offsetting credits to the Consolidated Statements of Income 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 Income was $153 million in 2017 (an equity component of $115 million and an interest expense component of $38 million), $168 million in 2016 (an equity component of $121 million and an interest expense component of $47 million) and $95 million in 2015 (an equity component of $76 million and an interest expense component of $19 million). The equity component of AFUDC, a non-cash item, is included as a reconciling item to net income within Cash Flows from Operating Activities - Change in Operating Assets and Liabilities in the Consolidated Statements of Cash Flows.

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 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, 2017, the difference between the tax basis and the reported amounts of Spectra Energy Partners' assets and liabilities is $14.7 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 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 are considered cash equivalents, except for the investments that were pledged as collateral against long-term debt as discussed in Note 14 and any investments that are considered restricted funds.

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. Upon disposition, natural gas inventory is recorded to Operating, maintenance and other expenses at the weighted average cost of inventory, including any adjustments recorded to reduce inventory to market value. Disposition of materials and supplies will be recorded to Operating, maintenance and other expenses.

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 Income or Consolidated Statements of Cash Flows. Receivables include $106 million and $99 million as of December 31, 2017 and December 31, 2016, respectively, and Other Current Liabilities include $80 million and $74 million as of December 31, 2017 and December 31, 2016, 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 (Loss) 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 11 and 15 for additional information.

Goodwill. Goodwill represents the excess of the purchase price over the fair value of net identifiable assets on acquisition of a business. The carrying value of goodwill, which is not amortized, is assessed for impairment annually, or more frequently if events or changes in circumstances arise that suggest the carrying value of goodwill may be impaired.

We perform our annual review for impairment at the reporting unit level, which is identified by assessing whether the components of our operating segments constitute businesses for which discrete information is available, whether segment management regularly reviews the operating results of those components and whether the economic and regulatory characteristics are similar. We have the option to first assess qualitative factors to determine whether it is necessary to perform the quantitative goodwill impairment test. The quantitative goodwill impairment test involves determining the fair value of our reporting units and comparing those values to the carrying value of each reporting unit. If the carrying value of a reporting unit, including allocated goodwill, exceeds its fair value, goodwill impairment is measured at the amount by which the reporting unit's carrying value exceeds its fair value. This amount should not exceed the carrying amount of goodwill. No impairments of goodwill were recorded in 2017, 2016 or 2015.

We had goodwill balances of $2,957 million at December 31, 2017 and $3,234 million at December 31, 2016. The decrease in goodwill in 2017 was the result of $282 million relating to the deconsolidation of Sabal Trail, partially offset by foreign currency translation.

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Property, Plant and Equipment. Property, plant and equipment is recorded at historical cost. Expenditures for construction, expansion, major renewals and betterments are capitalized. Maintenance and repair costs are expensed as incurred. Expenditures for project development are capitalized if they are expected to have future benefit. We capitalize interest incurred during construction for non rate-regulated assets. For rate-regulated assets, AFUDC is included in the cost of property, plant and equipment and is depreciated over future periods as part of the total cost of the related asset. AFUDC includes both an interest component and, if approved by the regulator, a cost of equity component.

Depreciation is generally provided on a straight-line basis over the estimated useful lives of the assets commencing when the asset is placed in service. When group assets are retired or otherwise disposed of, gains and losses are not reflected in earnings but are booked as an adjustment to accumulated depreciation.

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 and 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 incurred are reversed and capitalized as Property, Plant and Equipment.

Asset Impairments. We review the carrying values of its long-lived assets as events or changes in circumstances warrant. If it is determined that the carrying value of an asset exceeds the undiscounted cash flows expected from the asset, the asset is written down to fair value.

With respect to investments in debt and equity securities, we assess at each balance sheet date whether there is objective evidence that a financial asset is impaired by completing a quantitative or qualitative analysis of factors impacting the investment. If there is determined to be objective evidence of impairment, we value the expected discounted cash flows using observable market inputs and determines whether the decline below carrying value is other than temporary. If the decline is determined to be other than temporary, an impairment charge is recorded in earnings with an offsetting reduction to the carrying value of the asset.

With respect to other financial assets, we assess the assets for impairment when it no longer has reasonable assurance of timely collection. If evidence of impairment is noted, we reduce the value of the financial asset to its estimated realizable amount, determined using discounted expected future cash flows.

We recorded a $9 million non-cash impairment charge on Ozark Gas Gathering, L.L.C. in the first quarter of 2015 included in Operating, Maintenance and Other on the Consolidated Statements of Income.

Asset Retirement Obligations (AROs). AROs associated with the retirement of long-lived assets are measured at fair value and recognized in the period in which they can be reasonably determined. The fair value approximates the cost a third party would charge to perform the tasks necessary to retire such assets and is recognized at the present value of expected future cash flows. AROs are added to the carrying value of the associated asset and depreciated over the asset's useful life. The corresponding liability is accreted over time through charges to earnings and is reduced by actual costs of decommissioning and reclamation. Our estimates of retirement costs could change as a result of changes in cost estimates and regulatory requirements.

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 issued. 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

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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 for which separate financial information is available and evaluated regularly by the chief operating decision maker in deciding how to allocate resources and evaluate performance. Two or more operating segments may be aggregated into a single reportable segment provided certain criteria are met. There is no such aggregation within our defined business segments. A description of our reportable segments consistent with how business results are reported internally to management, and the disclosure of segment information is presented in Note 5.
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 Equity Investments. We consider distributions received from equity investments 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. The following new Accounting Standards Updates (ASUs) were adopted during 2017 and the effects of such adoptions, if any, are presented in the accompanying Consolidated Financial Statements:
Simplifying the Measurement of Goodwill Impairment. Effective January 1, 2017, we early adopted ASU 2017-04 and applied the standard on a prospective basis. Under the new guidance, goodwill impairment will now be the amount by which a reporting unit’s carrying value exceeds its fair value; this amount should not exceed the carrying amount of goodwill. The adoption of the pronouncement did not have a material impact on our consolidated financial statements.

Clarifying the Definition of a Business in an Acquisition. Effective January 1, 2017, we early adopted ASU 2017-01 on a prospective basis. The new standard was issued with the objective of adding guidance to assist entities with evaluating whether transactions should be accounted for as acquisitions (disposals) of assets or businesses. The adoption of the pronouncement did not have a material impact on our consolidated financial statements.

Accounting for Intra-Entity Asset Transfers. Effective January 1, 2017, we early adopted ASU 2016-16 on a modified retrospective basis. The new standard was issued with the intent of improving the accounting for the income tax consequences of intra-entity asset transfers other than inventory. Under the new guidance, an entity should recognize the income tax consequences of an intra-entity transfer of an asset, other than inventory, when the transfer occurs. The adoption of the pronouncement did not have a material impact on our consolidated financial statements.

Improvements to Employee Share-Based Payment Accounting. Effective January 1, 2017, we adopted ASU 2016-09 and applied certain amendments on a modified retrospective basis with the remaining amendments applied on a prospective basis. The new standard was issued with the intent of simplifying and improving several aspects of accounting for share-based payment transactions including the income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows. The adoption of the pronouncement did not have a material impact on our consolidated financial statements.

Simplifying the Embedded Derivatives Analysis for Debt Instruments. Effective January 1, 2017, we adopted ASU 2016-06 on a modified retrospective basis. The new guidance simplifies the embedded derivative analysis for debt instruments containing contingent call or put options. The adoption of the pronouncement did not have a material impact on our consolidated financial statements.

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Pending. The following new ASUs have been issued but not yet adopted:

Improvements to Accounting for Hedging Activities. ASU 2017-12 was issued in August 2017 with the objective of better aligning a company's risk management activities and the resulting hedge accounting reflected in the financial statements. The accounting update allows cash flow hedging of contractually specified components in financial and non-financial items. Under the new guidance, hedge ineffectiveness is no longer required to be measured and hedging instruments' fair value changes will be recorded in the same statement of income line as the hedged item. The ASU also allows the initial quantitative hedge effectiveness assessment to be performed at any time before the end of the quarter in which the hedge is designated. After initial quantitative testing is performed, an ongoing qualitative effectiveness assessment is permitted. The accounting update is effective January 1, 2019 and is to be applied on a modified retrospective basis. We are currently assessing the impact of the new standard on our consolidated financial statements.

Clarifying Guidance on the Application of Modification Accounting on Stock Compensation. ASU 2017-09 was issued in May 2017 with the intent to clarify the scope of modification accounting and when it should be applied to a change to the terms or conditions of a share based payment award. Under the new guidance, modification accounting is required for all changes to share based payment awards, unless all of the following are met: 1) there is no change to the fair value of the award, 2) the vesting conditions have not changed, and 3) the classification of the award as an equity instrument or a debt instrument has not changed. The accounting update is effective January 1, 2018 and will be applied on a prospective basis. We do not expect the adoption of this accounting update to have a material impact on our consolidated financial statements.

Improving the Presentation of Net Periodic Benefit Cost related to Defined Benefit Plans. ASU 2017-07 was issued in March 2017 primarily to improve the statement of income presentation of the components of net periodic pension cost and net periodic postretirement benefit cost for an entity's sponsored defined benefit pension and other postretirement plans. In addition, only the service cost component of net benefit cost is eligible for capitalization. The accounting update is effective January 1, 2018 and will be applied on a retrospective basis for the statement of income presentation component and a prospective basis for the capitalization component. We do not expect the adoption of this accounting update to have a material impact on our consolidated financial statements.

Clarifying Guidance on Derecognition and Partial Sales of Nonfinancial Assets. ASU 2017-05 was issued in February 2017 with the intent of clarifying the scope of asset derecognition guidance and accounting for partial sales of nonfinancial assets. The ASU clarifies the scope provisions of nonfinancial assets and how to allocate consideration to each distinct asset, and amends the guidance for derecognition of a distinct nonfinancial asset in partial sale transactions. The accounting update is effective January 1, 2018 and will be applied on a modified retrospective basis. We do not expect the adoption of this accounting update to have a material impact on our consolidated financial statements.

Clarifying the Presentation of Restricted Cash in the Statement of Cash Flows. ASU 2016-18 was issued in November 2016 with the intent to clarify guidance on the classification and presentation of changes in Restricted cash and restricted cash equivalents within the Consolidated Statement of Cash Flows. The accounting update requires that changes in Restricted cash and restricted cash equivalents be included within Cash and cash equivalents when reconciling the opening and closing period amounts shown on the Consolidated Statement of Cash Flows. We currently present the changes in Restricted cash and restricted cash equivalents under Investing activities in the Consolidated Statement of Cash Flows. The accounting update is effective January 1, 2018 and will be applied on a retrospective basis. We will amend the presentation in the Consolidated Statement of Cash Flows to include Restricted cash and restricted cash equivalents with cash and cash equivalents and we will retrospectively reclassify all periods presented.

Simplifying Cash Flow Classification. ASU 2016-15 was issued in August 2016 with the intent of reducing diversity in practice of how certain cash receipts and cash payments are classified in the Consolidated Statement of Cash Flows. The new guidance addresses eight specific presentation issues. The accounting update is effective January 1, 2018 and will be applied on a retrospective basis. We assessed each of the eight specific presentation issues and the adoption of this ASU does not have a material impact on our consolidated financial statements.

Accounting for Credit Losses. ASU 2016-13 was issued in June 2016 with the intent of providing financial statement users with more useful information about the expected credit losses on financial instruments and other commitments to extend credit held by a reporting entity at each reporting date. Current treatment uses the incurred

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loss methodology for recognizing credit losses that delays the recognition until it is probable a loss has been incurred. The accounting update adds a new impairment model, known as the current expected credit loss model, which is based on expected losses rather than incurred losses. Under the new guidance, an entity recognizes as an allowance its estimate of expected credit losses, which the Financial Accounting Standards Board believes will result in more timely recognition of such losses. We are currently assessing the impact of the new standard on our consolidated financial statements. The accounting update is effective January 1, 2020.

Recognition of Leases. ASU 2016-02 was issued in February 2016 with the intent to increase transparency and comparability among organizations. It requires lessees of operating lease arrangements to recognize lease assets and lease liabilities on the Consolidated Balance Sheets and disclose additional key information about lease agreements. The accounting update also replaces the current definition of a lease and requires that an arrangement be recognized as a lease when a customer has the right to obtain substantially all of the economic benefits from the use of an asset, as well as the right to direct the use of the asset. We are currently gathering a complete inventory of our lease contracts in order to assess the impact of the new standard on our consolidated financial statements. The accounting update is effective January 1, 2019 and will be applied using a modified retrospective approach.

Recognition and Measurement of Financial Assets and Liabilities. ASU 2016-01 was issued in January 2016 with the intent to address certain aspects of recognition, measurement, presentation and disclosure of financial assets and liabilities. Investments in equity securities, excluding equity method and consolidated investments, are no longer classified as trading or available-for-sale securities. All investments in equity securities with readily determinable fair values are classified as investments at fair value through net income. Investments in equity securities without readily determinable fair values are measured using the fair value measurement alternative and are recorded at cost minus impairment, if any, plus or minus changes resulting from observable price changes in orderly transactions for an identical or similar investment of the same issuer. Investments in equity securities measured using the fair value measurement alternative are reviewed for indicators of impairment each reporting period. Fair value of financial instruments for disclosure purposes is measured using exit price. The accounting update is effective January 1, 2018 and will be applied on a prospective basis. We do not expect the adoption of this accounting update to have a material impact on our consolidated financial statements.

Revenue from Contracts with Customers. ASU 2014-09 was issued in 2014 with the intent of significantly enhancing consistency and comparability of revenue recognition practices across entities and industries. The new standard establishes a single, principles-based five-step model to be applied to all contracts with customers and introduces new and enhanced disclosure requirements. It also requires the use of more estimates and judgments than the present standards in addition to additional disclosures. The new standard is effective January 1, 2018. The new standard permits either a full retrospective method of adoption with restatement of all prior periods presented, or a modified retrospective method with the cumulative effect of applying the new standard recognized as an adjustment to opening retained earnings in the period of adoption. We have decided to adopt the new standard using the modified retrospective method.

We have reviewed our revenue contracts in order to evaluate the effect of the new standard on our revenue recognition practices. Based on this assessment, the application of the standard will result in the following change to our financial statements and revenue recognition methods:

- Certain payments received from customers to offset the cost of constructing assets required to provide services to those customers, referred to as Contributions in Aid of Construction ("CIACs") were previously recorded as reductions of property, plant and equipment regardless of whether the amounts were imposed by regulation or negotiated. Under the new standard, negotiated CIACs are deemed to be advance payments for services and must be recognized when those future services are provided. Negotiated CIACs will be accounted for as deferred revenue and recognized over the term of the associated revenue contract.

After conducting this assessment any adjustments to our partner's capital account will be immaterial as of January 1, 2018.

We have also developed and tested processes to generate the disclosures which will be required under the new standard commencing in the first quarter of 2018.

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3. Acquisition and Disposition
U.S. Assets Dropdown. During 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. This was the first of three planned transactions.
In November 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 our general partner in exchange for the same amount of common units in order to maintain the general partner's 2% general partner interest.
In November 2015, we acquired the remaining 0.1% ownership interest in SESH from Spectra Energy. Total consideration was 17,114 newly issued common units. This was the last of three planned transactions related to the U.S. Assets Dropdown. Also in connection with this transaction, we issued 342 general partner units to our general patner in exchange for the same amount of common units in order to maintain the general partner's 2% general partner interest.
Disposition. In October 2015, Spectra Energy acquired our 33.3% ownership interests in DCP Sand Hills Pipeline, LLC (Sand Hills) and DCP Southern Hills Pipeline, LLC (Southern Hills). In consideration for this transaction, we retired 21,560,000 of our common units and 440,000 of our general partner units beneficially held by Spectra Energy, which will result in the reduction of distributions ultimately payable to Spectra Energy for the related units retired. Additional consideration consisted of a reduction in the aggregate quarterly distributions, if any, to our general partner, as holder of incentive distribution rights, by $4 million per quarter for a period of 12 consecutive quarters commencing with the quarter ending on December 31, 2015 and ending on September 30, 2018. The total reduction of distributions to our general partner was $16 million and $16 million for the years ended December 31, 2017 and 2016, respectively. This transfer of assets between entities under common control is included as a non-cash transaction in the Consolidated Statements of Cash Flows. See Note 7 for additional information on the Equity Restructure Agreement entered into on January 21, 2018 with our General Partner.
4. Related Party Transactions
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 Income

	2017	2016	2015
	(in millions)		
Operating revenues	$41	$ 34	$ 53
Operating, maintenance and other expenses	314	310	457

We are party to an agreement with DCP Midstream, LLC (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 natural gas liquids 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 $36 million, $31 million and $46 million in 2017, 2016 and 2015,

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respectively, related to those services, classified as Storage of Natural Gas and Other in our Consolidated Statements of Income.

We recorded natural gas transmission revenues from DCP Midstream and its affiliates totaling $1 million in 2017, $1 million in 2016 and $4 million in 2015, classified as Transportation of Natural Gas in our Consolidated Statements of Income.

In addition to the above, we recorded other revenues from DCP Midstream and its affiliates totaling $2 million in 2017, $2 million in 2016 and $3 million in 2015, classified as Storage of Natural Gas and Other in our Consolidated Statements of Income.

Consolidated Balance Sheets

	December 31,	
	2017	2016
	(in millions)	
Receivables	$ 10	$ 22
Current assets — other	1	2
Accounts payable	32	27
Current liabilities — other	16	10

Transactions billed from affiliates, included within Property, Plant and Equipment in the Consolidated Balance Sheets, were $93 million in 2017 and $46 million in 2016.

Gulfstream. During the third quarter of 2015, Gulfstream Natural Gas System, LLC (Gulfstream) issued unsecured debt of $800 million to fund the repayment of its current debt. Gulfstream distributed $396 million, our proportionate share of proceeds, to us, classified as Cash Flows from Investing Activities - Distributions from Equity Investments, of which we contributed $248 million back to Gulfstream in the fourth quarter of 2015 and the remaining $148 million, classified as Cash Flows from Investing Activities - Distributions to Equity Investment, in the second quarter of 2016.

See also Notes 1, 8 and 15 for discussion of specific related party transactions.

5. 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 FERC and the Department of Transportation’s (DOT’s) rules and regulations. Our investments in Gulfstream, SESH, Steckman Ridge and Sabal Trail are included in U.S. Transmission.

The Liquids segment provides transportation of crude oil. The Express-Platte pipeline system (Express-Platte) 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 NEB. We held direct one-third ownership interests in Sand Hills and Southern Hills until October 30, 2015.

Our reportable segments offer different products and services and are managed separately as business units. Management evaluates segment performance based on earnings 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	Asset
	(in millions)				
2017					
U.S. Transmission	$1,545	$ 1,199	$ 314	$ 2,204	$20,157
Liquids	405	259	32	21	1,875
Total	1,950	1,458	346	2,225	22,032
Other	—	(127)	—	—	24
Depreciation and amortization	—	346	—	—	—
Interest expense	—	265	—	—	—
Interest income and other	—	2	—	—	—
Total consolidated	$1,950	$ 722	$ 346	$ 2,225	$22,056
2016					
U.S. Transmission	$2,167	$ 1,639	$ 285	$ 2,514	$19,747
Liquids	366	237	29	71	1,841
Total	2,533	1,876	314	2,585	21,588
Other	—	(82)	—	—	18
Depreciation and amortization	—	314	—	—	—
Interest expense	—	224	—	—	—
Interest income and other	—	1	—	—	—
Total consolidated	$2,533	$ 1,257	$ 314	$ 2,585	$21,606
2015					
U.S. Transmission	$2,087	$ 1,599	$ 264	$ 1,952	$17,050
Liquids	368	283	31	55	1,778
Total	2,455	1,882	295	2,007	18,828
Other	—	(66)	—	—	23
Depreciation and amortization	—	295	—	—	—
Interest expense	—	239	—	—	—
Interest income and other	—	(5)	—	—	—
Total consolidated	$2,455	$ 1,277	$ 295	$ 2,007	$18,851

Geographic Data

	U.S.	Canada	Consolidated
	(in millions)		
2017			
Consolidated revenues	$1,865	$ 85	$ 1,950
Consolidated long-lived assets	17,958	227	18,185
2016			
Consolidated revenues	$2,456	$ 77	$ 2,533
Consolidated long-lived assets	19,580	215	19,795
2015			
Consolidated revenues	$2,383	$ 72	$ 2,455
Consolidated long-lived assets	18,104	203	18,307

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6. Regulatory Matters
Regulatory Assets and Liabilities
We record assets and liabilities that result from the regulated ratemaking process that would not be recorded under GAAP for non-regulated entities. See Note 2 for further discussion.
Financial Statement Effects
The following items are reflected in the consolidated balance sheets. All regulatory assets and liabilities are excluded from rate base unless otherwise noted below.

	Recovery/Refund Period Ends	December 31, 2017	2016
		(in millions)	
Regulatory Assets (a)			
Regulatory asset related to income taxes (b)	Various	$137	$297
Vacation accrual	Various	17	19
Deferred debt expense/premium	Various	14	18
Asset retirement obligations	Various	22	17
Under-recovery of fuel costs (c,d)	—	19	6
Project development costs	Through 2036	8	9
Other	—	3	10
Total Regulatory Assets		$220	$376
Regulatory Liabilities			
Over-recovery of fuel costs (d,e)	—	$15	$38
Deferred income taxes (f,g)	Various	860	—
Pipeline rate credit (g)	Life of associated liability	21	23
Total Regulatory Liabilities		$896	$61

(a)Included in Regulatory and Other Assets, unless otherwise noted.
(b)Relates to tax gross-up of the AFUDC equity portion on certain pipelines' rate mechanisms. All amounts are expected to be included in future rate filings.
(c)Included in Fuel Tracker.
(d)Includes amounts settled in cash annually through transportation rates in accordance with FERC gas tariffs.
(e)Included in Current Liabilities - Other.
(f)Relates to the establishment of a regulatory liability as a result of the U.S. tax reform legislation dated December 22, 2017.
(g)Included in Regulatory and Other Liabilities.

7. Net Income Per Limited Partner Unit and Cash Distributions
We allocate our net income among our general partner interest and our limited partner units using the two-class method in accordance with applicable authoritative accounting guidance. Under the two-class method, we allocate our net income attributable to our General Partner and our limited partners according to the distribution formula for available cash as set forth in our partnership agreement. We also allocate any earnings in excess of distributions to our General Partner and limited partners utilizing the distribution formula for available cash specified in our partnership agreement.
On January 21, 2018, we entered into an Equity Restructuring Agreement with our GP, LP, pursuant to which the incentive distribution rights and the 2% general partner interest in us held by GP, LP were converted into 172,500,000

newly issued common units of Spectra Energy Partners and a non-economic general partner interest in us. Immediately after the execution of our Equity Restructuring Agreement, a new limited partnership agreement was entered into. The distribution for the fourth quarter of 2017 was declared after January 21, 2018, and will be paid in accordance with this new limited partnership agreement.

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We determined basic and diluted net income per limited partner unit as follows:

	2017	2016	2015
	(in millions, except per unit amounts)		
Net income—controlling interests	$609	$1,161	$1,225
Less net income attributable to:			
General partner's interest in general partner units—2%	12	23	24
General partner's interest in incentive distribution rights	357	288	225
Limited partners' interest in net income attributable to common units	$240	$850	$976
Weighted average limited partner units outstanding—basic and diluted	310	299	296
Net income per limited partner unit—basic and diluted	$0.77	$2.84	$3.30

Our 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.

Available Cash. Available Cash, for any quarter, consists of all cash and cash equivalents on hand at the end of that quarter:

- less the amount of cash reserves established by the general partner to:
- provide for the proper conduct of business,
- comply with applicable law, any debt instrument or other agreement, or
- provide funds for minimum quarterly distributions to the unitholders and to the general partner for any one or more of the next four quarters,
- plus, if the general partner so determines, all or a portion of cash and cash equivalents on hand on the date of determination of Available Cash for the quarter.

Incentive Distribution Rights. GP, LP, our general partner held through January 21, 2018 a 2% partner interest and incentive distribution rights (IDRs) in accordance with the Second Amended and Restated Agreement of Limited Partnership of Spectra Energy Partners, LP dated as of November 1, 2013, as amended by Amendment No.1 dated as of July 2, 2015 and Amendment No. 2 dated as of November 20, 2017 as follows:

Distribution Targets	Portion of Quarterly Distribution per Common Unit	Marginal Percentage Interest in Distributions: Unitholders	Marginal Percentage Interest in Distributions: General Partner
Minimum Quarterly Distribution	up to $0.30	98 %	2 %
First Target Distribution	>$0.30 to $0.345	98 %	2 %
Second Target Distribution	>$0.345 to $0.375	85 %	15 %
Third Target Distribution	>$0.375 to $0.45	75 %	25 %
Thereafter	>$0.45	50 %	50 %

To the extent distributions are made to GP, LP with respect to its IDRs, there would be more Available Cash proportionately allocated to GP, LP than to holders of common units. A cash distribution of $0.73875 per limited partner unit was declared on February 8, 2018 and is payable on February 28, 2018 to unitholders of record at the close of business on February 20, 2018.

As a result of the sale of our interests in Sand Hills and Southern Hills to Spectra Energy in October 2015, there was a reduction in the aggregate quarterly distributions, if any, to our general partner, (as holder of the IDRs), by $4 million per quarter for a period of 12 consecutive quarters ending on September 30, 2018 (the IDR Give-Back). See Note 3 for more information.

As a result of the Equity Restructuring Agreement, the IDRs, the 2% general partner interest, and the IDR Give-Back were eliminated effective January 21, 2018, and distributions by us with a record date after January 21, 2018, will be made based on the terms of our limited partnership agreement in effect at the time of declaration.

Immediately after the execution of our Equity Restructuring Agreement, a new limited partnership agreement was entered into. The distribution for the fourth quarter of 2017 was declared after January 21, 2018, and will be paid in accordance with this new limited partnership agreement.

8. Investments in and Loans to Unconsolidated Affiliates

Investments in affiliates for which we are not the primary beneficiary, but over which we have significant influence, are accounted for using the equity method. As of December 31, 2017 and 2016, the carrying amounts of investments in affiliates approximated the amounts of underlying equity in net assets. We received distributions from our equity investments of $185 million in 2017, $160 million in 2016 and $610 million in 2015. Cumulative undistributed earnings from equity investments totaled $47 million, $15 million, and $5 million in 2017, 2016, and 2015, respectively.

U.S. Transmission. Investments are comprised of a 50% interest in Sabal Trail, 50% interest in Gulfstream, a 50% interest in SESH, a 50% interest in Steckman Ridge, a 50% interest in Nexus Gas Transmission, LLC (Nexus), and a 20% interest in PennEast Pipeline (PennEast).

We have a loan outstanding to Steckman Ridge in connection with the construction of its storage facilities. The loan carries market-based interest rates and is due the earlier of October 1, 2023 or coincident with the closing of any long-term financings by Steckman Ridge. The loan receivable from Steckman Ridge, including accrued interest, totaled $71 million at both December 31, 2017 and 2016.

Liquids. Investments were comprised of 33.3% interests in Sand Hills and Southern Hills. The Sand Hills and Southern Hills pipelines were placed in service in the second quarter of 2013 and acquired by Spectra Energy in the fourth quarter of 2015.

Earnings from Equity Investments

	2017	2016	2015
	(in millions)		
U.S. Transmission (a)	$307	$127	$112
Liquids	—	—	55
Total	$307	$127	$167

(a) Includes $106 million related to the gain recognized as a result of the deconsolidation and re-measurement of Sabal Trail.

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

Statements of Income

	2017			2016	2015
	Sabal Trail (a)	Other	Total	Total	Total
	(in millions)				
Operating revenues	$124	$430	$554	$430	$702
Operating expenses	52	118	170	118	229
Operating income	72	312	384	312	473
Net income	74	346	420	253	380

(a) Sabal Trail was deconsolidated as of July 1, 2017.

(b) Refer to Earnings from Equity Investments table above for net income attributable to the general partner.

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Balance Sheets

	December 31, 2017			2016
	Sabal Trail (a)	Other	Total	Total
	(in millions)			
Current assets	$ 67	$ 245	$ 312	$ 154
Non-current assets	2,977	4,441	7,418	3,665
Current liabilities	60	154	214	112
Non-current liabilities	—	1,680	1,680	1,678

(a) Sabal Trail was deconsolidated in Q3 2017.

9. Variable Interest Entities

Unconsolidated Variable Interest Entities

Sabal Trail. We own a 50% interest in Sabal Trail, a joint venture that operates a pipeline originating in Alabama that transports natural gas to Florida (the Sabal Trail pipeline). Sabal Trail is a variable interest entity (VIE) due to insufficient equity at risk to finance its activities.

On July 3, 2017, the Sabal Trail pipeline was placed into service. In accordance with the Sabal Trail LLC Agreement, upon the commencement of commercial service of the Sabal Trail pipeline, the power to direct Sabal Trail's activities became shared with its members. Consequently, we are no longer the primary beneficiary and as a result deconsolidated the assets, liabilities and non-controlling interests related to Sabal Trail at the in-service date.

At deconsolidation, our interest in Sabal Trail was recorded at its fair value of $1.9 billion. We recognized a gain of $106 million related to the remeasurement of the retained equity interest to its fair value. The gain was recorded in Earnings from Equity Investments on the Consolidated Statements of Income. The fair value was determined using the income approach which is based on the present value of future cash flows. The inputs used in the development of the fair value, representative of a Level 3 fair value measurement, include, but are not limited to, the amount and timing of projected future cash flows and a 9% discount rate used to measure the risks inherent in the future cash flows.

Subsequent to deconsolidation, we determined that we continue to have the ability to exercise significant influence over Sabal Trail and accounted for it under the equity method. Our maximum exposure to loss is $2.0 billion. We have an investment in Sabal Trail of $1.9 billion as of December 31, 2017, classified as Investments in and Loans to Unconsolidated Affiliates on our Consolidated Balance Sheets.

Nexus. We own a 50% equity investment in Nexus, a joint venture that is constructing a greenfield natural gas pipeline from Ohio to Michigan and leasing capacity on third party pipelines in order to provide transportation of Appalachian Basin natural gas to markets in Ohio, Michigan, and the Dawn Hub in Ontario, Canada through the Vector Pipeline. Nexus is a VIE due to insufficient equity at risk to finance its activities. We determined that we are not the primary beneficiary because the power to direct the activities of Nexus that most significantly impact its economic performance is shared. Our maximum exposure to loss is $1.2 billion. We have an investment in Nexus of $640 million and $356 million as of December 31, 2017 and December 31, 2016, respectively, classified as Investments in and Loans to Unconsolidated Affiliates on our Consolidated Balance Sheets.

On December 29, 2016, we issued performance guarantees to a third party and an affiliate on behalf of Nexus. See Note 19 for further discussion of the guarantee arrangement.

PennEast Pipeline. In June 2017, we purchased an additional 10% interest in PennEast from PSEG Power Gas Holdings, LLC, increasing our ownership interest in PennEast to 20%. PennEast is a joint venture that is proposing to construct a natural gas pipeline originating in northeastern Pennsylvania, and ending near Pennington, Mercer County, New Jersey. PennEast is a VIE due to insufficient equity at risk to finance its activities. We determined that we are not the primary beneficiary because the power to direct the activities of PennEast that most significantly impact its economic performance is shared. We account for PennEast under the equity method. Our maximum exposure to loss is $275 million. We have an investment in PennEast of $55 million and $11 million as of

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December 31, 2017 and December 31, 2016, respectively, classified as Investments in and Loans to Unconsolidated Affiliates on our Consolidated Balance Sheets.

The maximum exposure to loss for these entities is limited to our current equity investment and the remaining expected contributions for each joint venture.

10. Intangible Asset

During the first quarter of 2016 we entered into a project coordination agreement (PCA) with NextEra, Duke Energy Corporation and Williams Partners L.P. In accordance with the agreement, payments were made based on our proportional ownership interest in the Sabal Trail project as certain milestones of the project were met.

As December 31, 2017, all milestones were achieved and paid, totaling $120 million. As of December 31, 2016, two of the three milestones had been achieved and payments totaling $80 million were made. Payments are classified as Investing Activities — Additions to Intangible Assets, Net on our Consolidated Statements of Cash Flows. This PCA is an intangible asset and is classified as Regulatory and Other Assets on our Consolidated Balance Sheets.

The intangible asset is amortized over a period of 25 years, beginning at the in-service date of the project, which was July 3, 2017. The weighted average amortization rate of intangible assets is 4% as of December 31, 2017.

For the year ended December 31, 2017, our amortization expense related to the intangible asset totaled $2 million. The amortization expense for each of the next five years is estimated to be approximately $5 million.

11. Marketable Securities and Restricted Funds

We routinely invest excess cash and various restricted balances in securities such as commercial paper, corporate debt securities, and other money market securities in the United States, as well as equity securities in Canada. We do not purchase marketable securities for speculative purposes, therefore, we do not have any securities classified as trading securities. While we do not routinely sell marketable securities prior to their scheduled maturity dates, some of our investments may be held and restricted for the purposes of funding future capital expenditures and NEB regulatory requirements, so these investments are classified as AFS marketable securities as they may occasionally be sold prior to their scheduled maturity dates due to the unexpected timing of cash needs. Initial investments in securities are classified as purchases of the respective type of securities (AFS marketable securities or HTM marketable securities). Maturities of securities are classified within Proceeds from Sales and Maturities of Securities in the Consolidated Statements of Cash Flows.

AFS Securities. We had $3 million and $10 million of AFS securities classified as Regulatory and other assets on Consolidated Balance Sheets as of December 31, 2017 and December 31, 2016, respectively. At December 31, 2017 and December 31, 2016, these investments include less than $1 million and $9 million of restricted funds related to certain construction projects and $3 million and $1 million restricted funds held and collected from customers for Canadian pipeline abandonment in accordance with the NEB's regulatory requirements, respectively.

At December 31, 2017, the weighted-average contractual maturity of outstanding AFS securities was less than one year.

There were no material gross unrecognized holding gains or losses associated with investments in AFS securities at December 31, 2017 or December 31, 2016.

HTM Securities. All of our HTM securities are restricted funds. We had $3 million of money market securities classified as Other assets, net on the Consolidated Balance Sheets as of December 31, 2017 and December 31, 2016. These securities are restricted pursuant to certain Express-Platte debt agreements.

At December 31, 2017, the weighted-average contractual maturity of outstanding HTM securities was less than one year.

There were no material gross unrecognized holding gains or losses associated with investments in HTM securities at December 31, 2017 or December 31, 2016.

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Interest income. We had interest income of $1 million in 2017 and $2 million in 2016, which is included in Other income and expenses, net on the Consolidated Statements of Income. We had no interest income in 2015.
Other Restricted Funds. In addition to the AFS and HTM securities that were restricted funds as described above, we had other restricted funds totaling $4 million and $5 million classified as Regulatory and other assets on the Consolidated Balance Sheets at December 31, 2017 and December 31, 2016, respectively. These restricted funds are related to certain construction projects.
Changes in restricted balances are presented within Cash Flows from Investing Activities on our Consolidated Statements of Cash Flows.

12. Property, Plant and Equipment

	Weighted Average Depreciation Rate (%)		December 31,	
			2017	2016
			(in millions)	
Plant				
Natural gas transmission	1.88	%	$14,558	$13,702
Natural gas storage	2.04	%	1,655	1,638
Gathering and processing facilities	3.75	%	3	3
Crude oil transportation and storage	2.15	%	1,335	1,321
Land rights and rights of way	1.65	%	517	510
Other buildings and improvements	5.22	%	42	37
Equipment	4.79	%	81	81
Vehicles	4.34	%	10	12
Land	—		76	75
Construction in process (a)	—		482	2,494
Software	4.05	%	13	11
Other	1.48	%	221	74
Total property, plant and equipment			18,993	19,958
Total accumulated depreciation			(3,928)	(3,741)
Total accumulated amortization			(166)	(125)
Total net property, plant and equipment			$14,899	$16,092

(a) Sabal Trail Construction in process is no longer included in the 2017 PPE balance as a result of deconsolidation in Q3 2017.

Approximately 84% of our property, plant and equipment is regulated with estimated useful lives based on rates approved by the FERC. Composite weighted-average depreciation rates were 2% for 2017, 2016 and 2015.

Amortization expense of intangible assets totaled $12 million in 2017, $9 million in 2016, and $10 million in 2015. Estimated amortization expense for the next five years is approximately $12 million for 2018 and $14 million for 2019 through to 2022.

13. Asset Retirement Obligations

Our AROs relate mostly to the retirement of offshore pipelines and certain onshore assets, obligations related to right-of-way agreements and contractual leases for land use. AROs are adjusted each period for liabilities incurred or settled during the period, accretion expense and any revisions made to the estimated cash flows.

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A reconciliation of movements to our ARO liabilities is as follows:

	2017	2016
	(in millions)	
Balance at beginning of year	$46	$48
Accretion expense	2	2
Revisions in estimated cash flows	1	(4)
Liabilities settled	(11)	—
Balance at the end of year (a)	$38	$46

(a) Amounts included in Regulatory and other liabilities in the Consolidated Balance Sheets

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14. Debt

	December 31, 2017	December 31, 2016
	(in millions)	
Spectra Energy Partners		
2.95% senior notes due September 2018	$500	$500
Variable-rate senior term loan due November 2018	—	400
Variable-rate senior notes due June 2020	400	—
4.60% senior notes due June 2021	250	250
4.75% senior notes due March 2024	1,000	1,000
3.50% senior notes due March 2025	500	500
3.375% senior notes due October 2026	600	600
5.95% senior notes due September 2043	400	400
4.50% senior notes due March 2045	700	700
Texas Eastern		
6.00% senior notes due September 2017	—	400
4.125% senior notes due December 2020	300	300
2.80% senior notes due October 2022	500	500
7.00% senior notes due July 2032	450	450
Algonquin 3.51% senior notes due July 2024	350	350
East Tennessee 3.10% senior notes due December 2024	190	200
Express-Platte		
6.09% senior secured notes due January 2020	110	110
7.39% subordinated secured notes due 2017	—	12
Change in fair value of debt hedged	(2)	4
Other (a)	(39)	(37)
Credit Facility borrowings (b)(d)	270	—
Commercial paper (c)(d)	1,984	574
Total debt	8,463	7,213
Current portions of long-term debt	(500)	(416)
Commercial paper (c)(d)	—	(574)
Total long-term debt	$7,963	$6,223

(a) Primarily debt discount and debt issuance costs.
(b) Weighted-average rate was 2.61% as of December 31, 2017.
(c) Weighted-average rate was 1.92% as of December 31, 2017 and 1.12% as of December 31, 2016.
(d) Credit facility borrowings and commercial paper are supported by our long-term committed credit facility. In the fourth quarter, we determined we had both the intent and ability to refinance them on a long-term and therefore reclassified the corresponding amounts as long-term debt on the Consolidated Balance Sheet effective December 31, 2017.

Secured Debt. Secured debt, totaling $110 million as of December 31, 2017, includes project financings for Express-Platte. The notes are secured by the assignment of the Express-Platte transportation receivables and by the Express Canada assets.

Floating Rate Debt. Debt included approximately $2,654 million of floating-rate debt as of December 31, 2017 and $974 million as of December 31, 2016. The weighted average interest rate of borrowings outstanding that contained floating rates was 2.03% at December 31, 2017 and 1.44% at December 31, 2016.

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Credit Facility

The following table provides details of our external committed credit facility at December 31, 2017.

	Maturity Dates (a)	Total Facility	Draws (b)	Available
		(in millions)		
Spectra Energy Partners, LP	2022	$2,500	$2,254	$ 246

(a) Includes $336 million of commitments that expire in 2021.
(b) Includes facility draws and commercial paper issuances that are back-stopped by the credit facility.

Debt Covenant

Our credit facility agreement and term debt indentures include common events of default and covenant provisions, including a financial covenant, whereby accelerated repayment and/or termination of the agreements may result if we were to default on payment or violate certain covenants. As of December 31, 2017, we were in compliance with those covenants.

15. Fair Value Measurements

The following presents, for each of the fair value hierarchy levels, assets that are measured at fair value on a recurring basis as of December 31, 2017 and December 31, 2016.

Description	Consolidated Balance Sheet Caption	December 31, 2017			
		Total	Level 1	Level 2	Level 3
		(in millions)			
Canadian equity securities	Regulatory and other assets	3	3	—	—
Interest rate swaps	Other assets, net	4	—	4	—
Commodity swaps	Other assets, net	2	—	—	2
Total Assets		$9	$ 3	$ 4	$ 2
Interest rate swaps	Current Liabilities - Other	3	—	3	—
Interest rate swaps	Regulatory and other liabilities	5	—	5	—
Total Liabilities		8	—	8	—

Description	Consolidated Balance Sheet Caption	December 31, 2016			
		Total	Level 1	Level 2	Level 3
		(in millions)			
Corporate debt securities	Cash and cash equivalents	$145	$ —	$ 145	$ —
Corporate debt securities	Regulatory and other assets	9	—	9	—
Canadian equity securities	Cash and cash equivalents	1	1	—	—
Interest rate swaps	Regulatory and other assets	9	—	9	—
Total Assets		$164	$ 1	$ 163	$ —

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Level 1
Level 1 valuations represent quoted unadjusted prices for identical instruments in active markets.
Level 2 Valuation Techniques
Fair values of our financial instruments that are actively traded in the secondary market, including our long-term debt, are determined based on market-based prices. These valuations may include inputs such as quoted market prices of the exact or similar instruments, broker or dealer quotations, or alternative pricing sources that may include models or matrix pricing tools, with reasonable levels of price transparency.
For interest rate swaps, we utilize data obtained from a third-party source for the determination of fair value. Both the future cash flows for the fixed-leg and floating-leg of our swaps are discounted to present value.
Level 3 Valuation Techniques
Level 3 valuation techniques include the use of pricing models, discounted cash flow methodologies or similar techniques where at least one significant model assumption or input is unobservable. Level 3 financial instruments also include those for which the determination of fair value requires significant management judgment or estimation.
Financial Instruments. The fair values of financial instruments that are recorded and carried at book value are summarized in the following table. Judgment is required in interpreting market data to develop the estimates of fair value. These estimates are not necessarily indicative of the amounts we could have realized in current markets.

Consolidated Balance Sheet Caption	December 31, 2017 Book Value	December 31, 2017 Approximate Fair Value	December 31, 2016 Book Value	December 31, 2016 Approximate Fair Value
	(in millions)			
Note receivable, noncurrent (a)	$71	$ 71	$71	$ 71
Long-term fixed - rate debt, including current maturities (b)	5,850	6,211	6,272	6,455

(a)Included within Investments in and Loans to Unconsolidated Affiliates.
(b)Excludes unamortized items and fair value hedge carrying value adjustments.
The fair value of long-term debt is determined based on market-based prices as described in the Level 2 valuation technique described above and are classified as Level 2.
The fair values of cash and cash equivalents, restricted cash, short-term investments, accounts receivable, note receivable-noncurrent, accounts payable, credit facility borrowings, long-term variable-rate debt, commercial paper and short-term money market securities are not materially different from their carrying amounts because of the short-term nature of these instruments or because the stated rates approximate market rates.
During the 2017 and 2016 periods, there were no material adjustments to assets and liabilities measured at fair value on a nonrecurring basis.
16. Risk Management and Hedging Activities
Interest Rate Risk. Changes in interest rates expose us to risk as a result of our issuance of variable and fixed-rate debt and commercial paper. We manage our interest rate exposure by limiting our variable-rate exposures to percentages of total debt and by monitoring the effects of market changes in interest rates. We also enter into financial derivative instruments including, but not limited to, interest rate swaps to manage and mitigate interest rate risk exposure. For interest rate derivative instruments that are designated and qualify as fair value hedges, the gain or loss on the derivative as well as the offsetting loss or gain on the hedged item attributable to the hedged risk is recognized in the Consolidated Statements of Income. There were no significant amounts of gains or losses recognized in net income related to fair value hedges in 2017, 2016 or 2015.
At December 31, 2017, we had “pay floating — receive fixed” interest rate swaps outstanding with a total notional amount of $900 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 interest rate swaps expire in 2018 and thereafter. These swaps

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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.
We have elected to present the fair value of interest rate swaps that had netting or rights of offset arrangements on a gross basis in the Consolidated Balance Sheets. The following table shows the impact of interest rate swaps assets and liabilities had we elected to present these contracts on a net basis:

	December 31, 2017			December 31, 2016		
Description	Gross Amounts Presented in the Consolidated Balance Sheets	Amounts Available for Offset	Net Amount	Gross Amounts Presented in the Consolidated Balance Sheets	Amounts Available for Offset	Net Amount
	(in millions)					
Assets	$4	$ (1)	$ 3	$ 9	$ —	$ 9
Liabilities	(8)	1	(7)	—	—	—

For interest rate derivative instruments that are designated and qualify as cash flow hedges, the gain or loss on the derivative is recorded in Other Comprehensive Income (Loss) and is reclassified into earnings when the hedge item impacts earnings. Any ineffective portion of a cash flow hedge’s change in fair value is recognized each period in earnings. Since the third quarter of 2017, we have entered into pre-issuance interest rate swaps which were designated and qualified as cash flow hedges. The information of these cash flow swaps are presented as follows:

Date of Maturity & Contract Type	Accounting Treatment	Average Interest Rate	Notional Amount	Fair Value at December 31, 2017	2016
			(in millions)		
Contracts maturing in 2018	Cash Flow Hedge	2.44 %	1,360	$ 1	—
Contracts maturing in 2020	Cash Flow Hedge	2.70 %	250	(3)	—

We estimate that less than $1 million of AOCI will be reclassified into net income in the next 12 months related to these swaps.
The effects of derivative instruments on the Statements of Income and the Statements of Other Comprehensive Income are shown as follows:

	Years ended December 31,		
	2017	2016	2015
	(in millions)		
Amount of unrealized loss recognized in Other Comprehensive Income			
Cash flow	$ (2)	$ —	$ —

hedges - interest rate swaps			
Amount of (gain)/loss reclassified from AOCI to earnings (effective portion)			
Cash flow hedges - interest rate swaps (a)	—	—	(1)
Amount of (gain)/loss reclassified from AOCI to earnings (ineffective portion)			
Cash flow hedges - interest rate swaps (a)	(1)	—	—

(a) Reported within Interest Expense in the Consolidated Statements of Income.

Foreign Currency Risk. We are exposed to minimal foreign currency risk from our Express Canada operations. As a result, our earnings, cash flows and other comprehensive income (loss) are exposed to minimal fluctuations resulting from foreign exchange rate variability. There are no hedges in place to mitigate the exposure.

Commodity Price Risk Our earnings and cash flows are exposed to changes in commodity prices as a result of our ownership interests in certain assets. These commodities include natural gas, crude oil, power and NGL. We employ financial derivative instruments to fix a portion of the variable price exposures that arise from physical transactions involving these commodities. We use non-qualifying derivative instruments to manage commodity price risk. In July

2017, we entered into a power swap to fix a portion of the variable price exposure for power costs in our

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Express Canada operations until 2020. As a result, we recognized an unrealized gain of $2 million included with Storage of Natural Gas and Other on the Consolidated Statements of Income and a hedge asset of $2 million included with Other Assets, net on the Consolidated Balance Sheets.

Credit Risk. Our principal customers for natural gas transmission and storage services are local distribution companies, industrial end-users, and natural gas marketers located throughout the United States and Canada. 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 sectors throughout these regions. 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.

17. Changes in Operating Assets and Liabilities

	December 31,		
	2017	2016	2015
	(in millions)		
Accounts Receivable	$(7)	$(26)	$8
Other Current Assets	(31)	5	5
Accounts Payable	11	(20)	27
Taxes Payable	7	16	(3)
Other Current Liabilities	(2)	58	(6)
Other, assets	(117)	(127)	(70)
Other, liabilities	—	10	(4)
Changes in Operating Assets and Liabilities, net	$(139)	$(84)	$(43)

18. Commitments and Contingencies

Future Minimum Commitments

At December 31, 2017, we had commitments that have remaining non-cancelable terms in excess of one year as details below:

	2018	2019	2020	2021	2022	Thereafter	Total
	(in millions)						
Annual debt maturities (a) (b)	$500	$—	$810	$250	$2,754	$ 4,190	$8,504
Interest obligations (b)	260	247	238	210	204	1,756	2,915
Operating leases	15	19	18	17	19	120	208
Total	$775	$266	$1,066	$477	$2,977	$ 6,066	$11,627

(a) Includes senior notes, commercial paper, and credit facility borrowings based on the credit facility's maturity date. We have the ability under certain debt agreements to call and repay the obligations prior to scheduled maturities. Therefore, the actual timing of future cash repayments could be materially different than presented above.

(b) This table excludes the debt issuance that occurred subsequent to December 31, 2017 (Note 23).

We lease assets in various areas of our operations. Consolidated rental expense for operating leases classified in Net Income was $21 million in 2017, $22 million in 2016 and $23 million in 2015, which is included in Operating, Maintenance and Other on the Consolidated Statements of Income. Above is a summary of future minimum lease payments under operating leases which at inception had noncancellable terms of more than one year. We had no capital lease commitments at December 31, 2017.

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

Environmental

We are subject to various federal, state and local laws relating to the protection of the environment. These laws and regulations can change from time to time, imposing new obligations on us.

Environmental risk is inherent to liquid hydrocarbon and natural gas pipeline operations, and we and our affiliates are, at times, subject to environmental remediation at various contaminated sites. We manage this environmental risk through appropriate environmental policies and practices to minimize any impact our operations may have on the environment. We expense or capitalize, as appropriate, expenditures for ongoing compliance with environmental regulations that relate to past or current operations. We expense amounts we incur for remediation of existing environmental contamination caused by past operations that do not benefit future periods by preventing or eliminating future contamination. We record liabilities for environmental matters when assessments indicate that remediation efforts are probable, and the costs can be reasonably estimated. Estimates of environmental liabilities are based on currently available facts, existing technology and presently enacted laws and regulations taking into consideration the likely effects of inflation and other factors. These amounts also consider prior experience in remediating contaminated sites, other companies' clean-up experience and data released by government organizations. Our estimates are subject to revision in future periods based on actual costs or new information and are included in Regulatory and other liabilities in our consolidated balance sheets at their undiscounted amounts. We always have the potential of incurring additional costs in connection with environmental liabilities due to variations in any or all of the categories described above, including modified or revised requirements from regulatory agencies, in addition to fines and penalties, as well as expenditures associated with litigation and settlement of claims. We evaluate recoveries from insurance coverage separately from the liability and, when recovery is probable, we record and report an asset separately from the associated liability in our consolidated financial statements.

We recognize liabilities for other commitments and contingencies when, after fully analyzing the available information, we determine it is either probable that an asset has been impaired, or that a liability has been incurred and the amount of impairment or loss can be reasonably estimated. When a range of probable loss can be estimated, we accrue the most likely amount, or if no amount is more likely than another, we accrue the minimum of the range of probable loss. We expense legal costs associated with loss contingencies as such costs are incurred.

General Insurance

We are included in the comprehensive insurance program maintained by Enbridge for its subsidiaries. This program includes insurance coverage in types and amounts and is subject to certain deductibles, terms, exclusions and conditions that are generally consistent with coverage considered customary for our industry.

Other Litigation

We are subject to various other legal and regulatory actions and proceedings which arise in the normal course of business, including interventions in regulatory proceedings and challenges to regulatory approvals and permits by special interest groups. While the final outcome of such actions and proceedings cannot be predicted with certainty, we believe that the resolution of such actions and proceedings will not have a material impact on the consolidated financial position or results of operations.

Legal costs related to the defense of loss contingencies are expensed as incurred. We had no material reserves for legal matters recorded as of December 31, 2017 or 2016 related to litigation.

Other Commitments and Contingencies

See Note 19 for a discussion of guarantees and indemnifications.

19. Guarantees

In the normal course of conducting business, we enter into agreements which indemnify third parties and affiliates. Examples include indemnifying counterparties pursuant to sale agreements for assets or businesses in matters such as breaches of representations, warranties or covenants, loss or damages to property, environmental liabilities, changes in laws, valuation differences, litigation and contingent liabilities.

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On December 29, 2016, we issued performance guarantees to a third party and an affiliate on behalf of an equity method investee. These guarantees were issued to enable the equity method investee to enter into long-term transportation contracts with the third party. While the likelihood is remote, the maximum potential amount of future payments we could have been required to make as of December 31, 2017 was $90 million. These performance guarantees expire in 2032.

We cannot reasonably estimate the maximum potential amounts that could become payable to third parties and affiliates under these agreements; however, historically, we have not made any significant payments under indemnification provisions. While these agreements may specify a maximum potential exposure, or a specified duration to the indemnification obligation, there are circumstances where the amount and duration are unlimited. The indemnifications and guarantees have not had, and are not reasonably likely to have, a material effect on our financial condition, changes in financial condition, earnings, liquidity, capital expenditures or capital resources.

20. Issuances of Units

We have entered into equity distribution agreements for our at-the-market offering program up to $1 billion, pursuant to which we may offer and sell, through sales agents, common units representing limited partner interests at prices we deem appropriate. Sales of common units, if any, will be made by means of ordinary brokers' transactions on the New York Stock Exchange (NYSE), in block transactions, or as otherwise agreed to between the sales agent and us. We intend to use the net proceeds from sales under the program for general partnership purposes, which may include debt repayment, future acquisitions and capital expenditures.

	December 31,					
	2017		2016		2015	
Common Units	Number of Units	Amount	Number of Units	Amount	Number of Units	Amount
	(in millions)					
Balance at beginning of year	308.4	$11,650	285.1	$10,527	294.7	$10,474
Net income	—	240	—	850	—	976
Common units issued (a)	4.0	171	23.3	1,058	12.0	547
Common units retired	—	—	—	—	(21.6)	(794)
Distribution to limited partners	—	(878)	—	(785)	—	(728)
Consideration over net disposed assets	—	—	—	—	—	51
Other, net	—	—	—	—	—	1
Balance at end of year	312.4	$11,183	308.4	$11,650	285.1	$10,527

(a) Gross proceeds of $173 million, $1,064 million and $553 million for the years ended December 31, 2017, 2016, and 2015, respectively; net issuance costs of $2 million, $6 million and $7 million for the years ended December 31, 2017, 2016 and 2015, respectively.

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	December 31,					
	2017		2016		2015	
	Number of Units	Amount	Number of Units	Amount	Number of Units	Amount
General Partner Units	(in millions)					
Balance at beginning of year	6.3	$ 452	5.8	$ 336	6.0	$ 284
Net income	—	369	—	311	—	249
General partner units issued	0.1	3	0.5	22	0.2	11
General partner units retired	—	—	—	—	(0.4)	(15)
Attributed deferred tax benefit	—	(89)	—	59	—	39
Distribution to general partner	—	(349)	—	(276)	—	(233)
Consideration over net disposed assets	—	—	—	—	—	1
Balance at end of year	6.4	$ 386	6.3	$ 452	5.8	$ 336

21. Equity-Based Compensation

Phantom units are granted under a Long-Term Incentive Plan to certain employees of Spectra Energy and vest over three years. We did not award phantom units in 2017, 2016 or 2015. The remaining 7,500 units vested in 2015. We account for the phantom units as liability awards. Compensation expense for these awards was not significant in 2017, 2016 or 2015.

22. Quarterly Financial Data (Unaudited)

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
	(in millions, except per-unit amounts)				
2017					
Operating revenues (a)	$700	$ 695	$ 693	$ (138)	$1,950
Operating income (loss)	332	343	374	(486)	563
Net income (loss)	354	367	471	(489)	703
Net income (loss) attributable to controlling interests	317	328	460	(496)	609
Net income (loss) per limited partner unit (a)	0.74	0.75	1.15	(1.86)	0.77
2016					
Operating revenues	$624	$ 618	$ 628	$663	$2,533
Operating income	324	305	280	319	1,228
Net income	311	305	296	327	1,239
Net income attributable to controlling interests	298	287	275	301	1,161
Net income per limited partner unit (b)	0.80	0.71	0.64	0.70	2.84

(a) Operating revenues in the fourth quarter of 2017 are presented inclusive of the establishment of an $860 million estimated regulatory liability for the cost of service assets as a result of the 2017 US tax reform.

(b) Quarterly net income per limited partner unit amounts are stand-alone calculations and may not be additive to full-year amounts due to rounding and changes in outstanding units.

23. Subsequent Events

On January 9, 2018, Texas Eastern issued $400 million in aggregate principal amount of 3.50% senior notes due in 2028 and $400 million in aggregate principal amount of 4.15% senior notes due in 2048. Texas Eastern used a portion of the net proceeds from the offering to fund expansion projects and capital expenditures on the Texas Eastern pipeline system. In addition, Texas Eastern used a portion of the net proceeds from the offering to make a

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