Enable Midstream Partners, LP
Form 10-K
February 21, 2017
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

þ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF
THE SECURITIES AND EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2016
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 No. 1-36413

ENABLE MIDSTREAM PARTNERS, LP
(Exact name of registrant as specified in its charter)

Delaware	72-1252419
(State or jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

One Leadership Square
211 North Robinson Avenue
Suite 150
Oklahoma City, Oklahoma 73102
(Address of principal executive offices) (Zip Code)
Registrant's telephone number, including area code: (405) 525-7788

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.
þ Yes o No
Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Act.
o Yes þ No
Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. þ Yes ¨ No
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). þ Yes ¨ 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. ¨

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer þ	Accelerated filer ¨
Non-accelerated filer ¨ (Do not check if a smaller reporting company)	Smaller reporting company ¨

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

The aggregate market value of the Common Units held by non-affiliates of the registrant, based upon the closing price of $13.51 per common unit on June 30, 2016, was approximately $1,047 million.

As of February 1, 2017, there were 224,532,959 common units and 207,855,430 subordinated units outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

None

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GLOSSARY

2011 Pipeline Safety Act.	Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011.
Adjusted EBITDA.	Please read "Measures We Use to Evaluate Results of Operations" under Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operation" for the definition.
Adjusted interest expense.	Please read "Measures We Use to Evaluate Results of Operations" under Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operation" for the definition.
APSA.	Accountable Pipeline Safety and Partnership Act of 1996.
ArcLight.	ArcLight Capital Partners, LLC, a Delaware limited liability company, its affiliated entities ArcLight Energy Partners Fund V, L.P., ArcLight Energy Partners Fund IV, L.P., Bronco Midstream Partners, L.P., Bronco Midstream Infrastructure LLC and Enogex Holdings LLC, and their respective general partners and subsidiaries.
ASU.	Accounting Standards Update.
Atoka.	Atoka Midstream LLC, in which the Partnership owns a 50% interest as of December 31, 2016, which provides gathering and processing services.
Barrel.	42 U.S. gallons of petroleum products.
Bbl.	Barrel.
Bbl/d.	Barrels per day.
Bcf.	Billion cubic feet.
Bcf/d.	Billion cubic feet per day.
Board of Directors.	The board of directors of Enable GP, LLC.
Btu.	British thermal unit. When used in terms of volume, Btu refers to the amount of natural gas required to raise the temperature of one pound of water by one degree Fahrenheit at one atmospheric pressure.
CAA.	Clean Air Act, as amended.
CenterPoint Energy.	CenterPoint Energy, Inc., a Texas corporation, and its subsidiaries.
CERCLA.	Comprehensive Environmental Response, Compensation and Liability Act of 1980.
CFTC.	Commodity Futures Trading Commission.
CO2e.	Carbon dioxide equivalent.
Code.	The Internal Revenue Code of 1986, as amended.
Condensate.	A natural gas liquid with a low vapor pressure, mainly composed of propane, butane, pentane and heavier hydrocarbon fractions.
DCF.	Please read "Measures We Use to Evaluate Results of Operations" under Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operation" for the definition.
Delaware Act.	Delaware Revised Uniform Limited Partnership Act.
DHS.	Department of Homeland Security.
Distribution coverage ratio.	Please read "Measures We Use to Evaluate Results of Operations" under Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operation" for the definition.
Dodd-Frank Act.	Dodd-Frank Wall Street Reform and Consumer Protection Act.
DOT.	Department of Transportation.
EGT.	Enable Gas Transmission, LLC, a wholly owned subsidiary of the Partnership that operates a 5,900-mile interstate pipeline that provides natural gas transportation and storage services to customers principally in the Anadarko, Arkoma and Ark-La-Tex Basins in Oklahoma, Texas, Arkansas, Louisiana, Missouri and Kansas.
EIA.	Energy Information Administration.
EIIT.	

	Enable Illinois Intrastate Transmission, LLC, a wholly owned subsidiary of the Partnership that operates a 20-mile intrastate pipeline that provides natural gas transportation and storage services to customers in Illinois.
Enable GP.	Enable GP, LLC, a Delaware limited liability company and the general partner of Enable Midstream Partners, LP.

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Enable Midstream Services.	Enable Midstream Services, LLC, a wholly owned subsidiary of Enable Midstream Partners, LP.
Enogex.	Enogex LLC, a Delaware limited liability company, and its subsidiaries.
EOIT.	Enable Oklahoma Intrastate Transmission, LLC, formerly Enogex LLC, a wholly owned subsidiary of the Partnership that operates a 2,200-mile intrastate pipeline that provides natural gas transportation and storage services to customers in Oklahoma.
ESA.	Endangered Species Act.
EPA.	Environmental Protection Agency.
EPAct of 2005.	Energy Policy Act of 2005.
ERISA.	Employee Retirement Income Security Act of 1974.
Exchange Act.	Securities Exchange Act of 1934, as amended.
FASB.	Financial Accounting Standards Board.
FERC.	Federal Energy Regulatory Commission.
Fractionation.	The separation of the heterogeneous mixture of extracted NGLs into individual components for end-use sale.
GAAP.	Generally accepted accounting principles in the United States.
Gas imbalance.	The difference between the actual amounts of natural gas delivered from or received by a pipeline, as compared to the amounts scheduled to be delivered or received.
General partner.	Enable GP, LLC, a Delaware limited liability company, the general partner of Enable Midstream Partners, LP.
GHG.	Greenhouse gas.
Gross margin.	Please read “Measures We Use to Evaluate Results of Operations” under Item 7, “Management’s Discussion and Analysis of Financial Condition and Results of Operation” for the definition.
HCA.	High-consequence area.
HLPSA.	Hazardous Liquid Pipeline Safety Act of 1979.
Hinshaw pipeline.	A pipeline that is exempt from FERC’s NGA regulation if its operations are within a single state, if any gas received from interstate sources is received within the state and if its service is regulated by the state commission.
ICA.	Interstate Commerce Act.
IPO.	Initial public offering of Enable Midstream Partners, LP.
IRS.	Internal Revenue Service.
LDC.	Local distribution company involved in the delivery of natural gas to consumers within a specific geographic area.
Lean gas.	Natural gas that is primarily methane without NGLs.
LIBOR.	London Interbank Offered Rate.
LNG.	Liquefied natural gas.
MAOP.	Maximum allowable operating pressure for gas pipelines.
MBbl.	Thousand barrels.
MBbl/d.	Thousand barrels per day.
MFA.	Master Formation Agreement dated as of March 14, 2013.
MMcf.	Million cubic feet of natural gas.
MMBtu.	Million British thermal units.
MMcf/d.	Million cubic feet per day.
MOP.	Maximum operating pressure for hazardous liquid pipelines.
MRT.	Enable Mississippi River Transmission, LLC, a wholly owned subsidiary of the Partnership that operates a 1,600-mile interstate pipeline that provides natural gas transportation and storage services principally in Texas, Arkansas, Louisiana, Missouri and Illinois.
NEPA.	National Environmental Policy Act.
NGA.	Natural Gas Act of 1938.

NGPA.	Natural Gas Policy Act of 1978.

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NGPSA.	Natural Gas Pipeline Safety Act of 1968.
NGLs.	Natural gas liquids, which are the hydrocarbon liquids contained within natural gas including condensate.
NYMEX.	New York Mercantile Exchange.
NYSE.	New York Stock Exchange.
OCC.	Oklahoma Corporation Commission.
OGE Energy.	OGE Energy Corp., an Oklahoma corporation, and its subsidiaries.
OPA.	Oil Pollution Act of 1990.
OSHA.	Occupational Safety and Health Act of 1970.
Partnership.	Enable Midstream Partners, LP, and its subsidiaries.
Partnership Agreement.	Fourth Amended and Restated Agreement of Limited Partnership of Enable Midstream Partners, LP dated as of June 22, 2016.
PDO.	Petition for a Declaratory Order. Petition filed with FERC to seek regulatory assurances for key terms of service offered during an open season.
PHMSA.	Pipeline and Hazardous Materials Safety Administration.
PIPES Act.	Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006.
PSA.	Pipeline Safety Act of 1992.
PSIA.	Pipeline Safety Improvement Act of 2002.
PVIR.	Preventable Vehicle Incident Rate.
Purchase Agreement.	Purchase Agreement, dated January 28, 2016, by and between the Partnership and CenterPoint Energy, Inc. for the sale by the Partnership and purchase by CenterPoint Energy, Inc. of Series A Preferred Units.
RCRA.	Resource Conservation and Recovery Act of 1976.
Revolving Credit Facility	$1.75 billion senior unsecured revolving credit facility
RICE MACT.	Reciprocating internal combustion engines maximum achievable control technology.
Rich gas.	Natural gas containing higher concentrations of NGLs.
SCOOP.	South Central Oklahoma Oil Province.
SDWA.	Safe Drinking Water Act.
SEC.	Securities and Exchange Commission.
Securities Act.	Securities Act of 1933, as amended.
Series A Preferred Units.	10% Series A Fixed-to-Floating Non-Cumulative Redeemable Perpetual Preferred Units representing limited partner interests in the Partnership.
SESH.	Southeast Supply Header, LLC, in which the Partnership owns a 50% interest as of December 31, 2016, that operates an approximately 290-mile interstate natural gas pipeline from Perryville, Louisiana to southwestern Alabama near the Gulf Coast.
Sponsors.	CenterPoint Energy and OGE Energy.
STACK	Sooner Trend Anadarko Basin Canadian and Kingfisher Counties.
Superfund.	Comprehensive Environmental Response, Compensation and Liability Act of 1980.
TBtu.	Trillion British thermal units.
TBtu/d.	Trillion British thermal units per day.
Tcf.	Trillion cubic feet of natural gas.
Term Loan Agreements.	$450 million unsecured term loan agreement dated July 31, 2015 (2015 Term Loan Agreement) and $1.05 billion unsecured term loan agreement dated May 1, 2013 (2013 Term Loan Agreement).
TRIR.	Total Recordable Incident Rate.
WTI.	West Texas Intermediate.
2019 Notes.	$500 million 2.400% senior notes due 2019.
2024 Notes.	$600 million 3.900% senior notes due 2024.
2044 Notes.	$550 million 5.000% senior notes due 2044.

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FORWARD-LOOKING STATEMENTS

Some of the information in this report may contain forward-looking statements within the meaning of Section 27A of the Securities Act and Section 21E of the Exchange Act. Forward-looking statements give our current expectations, contain projections of results of operations or of financial condition, or forecasts of future events. Words such as "could," "will," "should," "may," "assume," "forecast," "position," "predict," "strategy," "expect," "intend," "plan," "estimate," "believe," "project," "budget," "potential," or "continue," and similar expressions are used to identify forward-looking statements. Without limiting the generality of the foregoing, forward-looking statements contained in this report include our expectations of plans, strategies, objectives, growth and anticipated financial and operational performance, including revenue projections, capital expenditures and tax position. Forward-looking statements can be affected by assumptions used or by known or unknown risks or uncertainties. Consequently, no forward-looking statements can be guaranteed.

A forward-looking statement may include a statement of the assumptions or bases underlying the forward-looking statement. We believe that we have chosen these assumptions or bases in good faith and that they are reasonable. However, when considering these forward-looking statements, you should keep in mind the risk factors and other cautionary statements in this report. Those risk factors and other factors noted throughout this report could cause our actual results to differ materially from those disclosed in any forward-looking statement. You are cautioned not to place undue reliance on any forward-looking statements. You should also understand that it is not possible to predict or identify all such factors and should not consider the following list to be a complete statement of all potential risks and uncertainties. Factors that could cause our actual results to differ materially from the results contemplated by such forward-looking statements include:

- changes in general economic conditions;
- competitive conditions in our industry;
- actions taken by our customers and competitors;
- the supply and demand for natural gas, NGLs, crude oil and midstream services;
- our ability to successfully implement our business plan;
- our ability to complete internal growth projects on time and on budget;
- the price and availability of debt and equity financing;
- strategic decisions by CenterPoint Energy and OGE Energy regarding their ownership of us and our General Partner;
- operating hazards and other risks incidental to transporting, storing, gathering and processing natural gas, NGLs, crude oil and midstream products;
- natural disasters, weather-related delays, casualty losses and other matters beyond our control;
- interest rates;
- labor relations;
- large customer defaults;
- changes in the availability and cost of capital;
- changes in tax status;
- the effects of existing and future laws and governmental regulations;
- changes in insurance markets impacting costs and the level and types of coverage available;
- the timing and extent of changes in commodity prices;
- the suspension, reduction or termination of our customers' obligations under our commercial agreements;
- disruptions due to equipment interruption or failure at our facilities, or third-party facilities on which our business is dependent;
- the effects of future litigation; and
- other factors set forth in this report and our other filings with the SEC.

Forward-looking statements speak only as of the date on which they are made. We expressly disclaim any obligation to update or revise any forward-looking statement, whether as a result of new information, future events or otherwise, except as required by law.

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PART I

Item 1. Business

Overview

Enable Midstream Partners, LP is a Delaware limited partnership formed in May 2013 by CenterPoint Energy, OGE Energy and ArcLight to own, operate and develop midstream energy infrastructure assets strategically located to serve our customers. We completed our IPO in April 2014, and we are traded on the NYSE under the symbol “ENBL.” Our general partner is owned by CenterPoint Energy and OGE Energy. In this report, the terms “Partnership” and “Registrant” as well as the terms “our,” “we,” “us” and “its,” are sometimes used as abbreviated references to Enable Midstream Partners, LP together with its consolidated subsidiaries.

Our assets and operations are organized into two reportable segments: (i) gathering and processing and (ii) transportation and storage. Our gathering and processing segment primarily provides natural gas and crude oil gathering and natural gas processing services to our producer customers. Our transportation and storage segment provides interstate and intrastate natural gas pipeline transportation and storage services primarily to our producer, power plant, LDC and industrial end-user customers.

Our natural gas gathering and processing assets are primarily located in Oklahoma, Texas, Arkansas and Louisiana and serve natural gas production in the Anadarko, Arkoma and Ark-La-Tex Basins. Our crude oil gathering assets are located in North Dakota and serve crude oil production in the Bakken Shale formation of the Williston Basin. Our natural gas transportation and storage assets consist primarily of an interstate pipeline system extending from western Oklahoma and the Texas Panhandle to Louisiana, an interstate pipeline system extending from Louisiana to Illinois, an intrastate pipeline system in Oklahoma and our investment in SESH, a pipeline extending from Louisiana to Alabama.

As of December 31, 2016, our portfolio of midstream energy infrastructure assets included:
- approximately 12,900 miles of gathering pipelines;
- 14 major processing plants with 2.5 Bcf/d of processing capacity;
- approximately 7,800 miles of interstate pipelines (including SESH);
- approximately 2,200 miles of intrastate pipelines; and
- eight natural gas storage facilities with 85.0 Bcf of storage capacity.

Our website address is www.enablemidstream.com. Documents and information on our website are not incorporated by reference in this report. Our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed with or furnished to the SEC are available, free of charge, on our website as soon as reasonably practicable after we electronically file or furnish such materials.

Our Business Strategies

Our primary business objective is to increase the cash available for distribution to our unitholders over time while maintaining our financial flexibility. We strive to meet this objective through the following strategies:

- Capitalize on Organic Growth Opportunities Associated with Our Strategically Located Assets: We own and operate assets servicing four of the largest basins in the United States, including some of the most productive shale plays in these basins. We intend to grow our business by developing new midstream energy infrastructure projects to support new and existing customers in these areas.

- Maintain Strong Customer Relationships to Attract New Volumes and Expand Beyond Our Existing Asset Footprint and Business Lines: Management believes that we have built a strong and loyal customer base through exemplary customer service and reliable project execution. We have invested in organic growth projects in support of our existing and new customers. We work to maintain and build relationships with key producers and suppliers in an effort to attract new volumes and expansion opportunities.
- Continue to Minimize Direct Commodity Price Exposure Through Fee-Based Contracts: We continually seek ways to minimize our exposure to commodity price risk. Management believes that focusing on fee-based revenues reduces our direct commodity price exposure. We intend to maintain our focus on increasing the percentage of long-term, fee-based contracts with our customers.

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- Grow Through Accretive Acquisitions and Disciplined Development. We continually evaluate potential acquisitions of complementary assets with the potential for attractive returns in new operating areas or midstream business lines. We will continue to analyze acquisition opportunities using disciplined financial and operating practices, including evaluating and managing risks to cash distributions.

Our Sponsors

CenterPoint Energy and OGE Energy each own a significant interest in us. As of December 31, 2016, CenterPoint Energy owned 54.1% of our common and subordinated units and 100% of our Series A Preferred Units, and OGE Energy owned 25.7% of our common and subordinated units. In addition, our sponsors own Enable GP, our general partner. As of December 31, 2016, CenterPoint Energy owned a 50% management interest and a 40% economic interest in our general partner, and OGE Energy owned a 50% management interest and a 60% economic interest in our general partner. Enable GP owns the non-economic general partner interest in us and all of our incentive distribution rights.

On February 18, 2016, we completed a private placement with CenterPoint Energy of 14,520,000 Series A Preferred Units for a cash purchase price of $25.00 per Series A Preferred Unit, resulting in proceeds of $362 million, net of issuance costs. For a further discussion regarding the Series A Preferred Units, see Note 5 of the Notes to Consolidated Financial Statements in Part II, Item 8. “Financial Statements and Supplementary Data.”

CenterPoint Energy (NYSE: CNP) is a public utility holding company whose operating subsidiaries provide electric transmission and distribution services and natural gas distribution services to customers primarily in Arkansas, Louisiana, Minnesota, Mississippi, Oklahoma and Texas.

OGE Energy (NYSE: OGE) is the parent company of Oklahoma Gas & Electric Company (OG&E), a regulated electric utility serving customers in Oklahoma and western Arkansas.

Our sponsors are customers of our transportation and storage business. For the year ended December 31, 2016, approximately 3% of our gross margin was derived from transportation and storage contracts with OG&E. For the year ended December 31, 2016, approximately 9% of our total gross margin was derived from transportation and storage contracts servicing LDCs owned by CenterPoint Energy.

In addition, our sponsors have entered into a number of agreements affecting us. For a more detailed description of our relationship and agreements with CenterPoint Energy and OGE Energy, please read Item 13. “Certain Relationships and Related Party Transactions.” Although management believes our relationships with CenterPoint Energy and OGE Energy are positive attributes, there can be no assurance that we will benefit from these relationships or that these relationships will continue.

Our Assets and Operations

Our assets and operations are organized into two reportable segments: (i) gathering and processing and (ii) transportation and storage.

Gathering and Processing

We own and operate substantial natural gas and crude oil gathering and natural gas processing assets in five states. Our gathering and processing operations consist primarily of natural gas gathering and processing assets serving the

Anadarko, Arkoma and Ark-La-Tex Basins and crude oil gathering assets serving the Williston Basin. We provide a variety of services to the active producers in our operating areas, including gathering, compressing, treating, and processing natural gas, fractionating NGLs, and gathering crude oil and produced water. We serve shale and other unconventional plays in the basins in which we operate, including the following:

- Anadarko Basin (Oklahoma, Texas Panhandle). We have natural gas gathering and processing operations in those portions of the Anadarko Basin located in Oklahoma and the Texas Panhandle where, as of December 31, 2016, we served over 200 producers. Our operations include gathering and processing natural gas produced from the Granite Wash, Cleveland, Marmaton, Tonkawa, Cana Woodford, SCOOP, STACK and Mississippi Lime plays. The current focus of our Anadarko Basin gathering and processing operations is on liquids-rich gas.

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- Arkoma Basin (Oklahoma, Arkansas). In the Arkoma Basin, our operations primarily serve the Woodford Shale play located in Oklahoma and the Fayetteville Shale play located in Arkansas. Our Arkoma Basin gathering and processing operations serve both liquids-rich and lean gas production. As of December 31, 2016, we served more than 70 producers in the Arkoma Basin.

- Ark-La-Tex Basin (Arkansas, Louisiana and Texas). We have gathering and processing operations in the Ark-La-Tex Basin located in Arkansas, Louisiana and Texas. Our Ark-La-Tex gathering and processing operations primarily serve the Haynesville, Cotton Valley and the lower Bossier plays. As of December 31, 2016, we served over 110 producers in the Ark-La-Tex Basin where our gathering and processing operations provide service for both liquids-rich and lean gas production.

- Williston Basin (North Dakota). In the Williston Basin, we have operations in the Bakken Shale that are located in North Dakota. The focus of our operations in the Bakken Shale is the gathering of crude oil and produced water for XTO Energy Inc. (XTO), an affiliate of ExxonMobil Corporation, with pipeline gathering systems in Dunn, McKenzie, Williams and Mountrail Counties of North Dakota.

Please see “Note 18. Reportable Business Segments” included in “Item 8. Financial Statements and Supplementary Data—Notes to Audited Consolidated Financial Statements” for gathering and processing segment information related to Total Revenues, Operating Income and Total Assets.

Capacity volumes for our facilities are measured based on physical volume and stated in cubic feet (“Bcf” or “MMcf”). Throughput volumes are measured based on energy content and stated in British thermal units (“MMBtu” or “TBtu”). A volume capacity of 100 MMcf generally correlates to volume capacity of 100,000 MMBtu. Crude oil and condensate are measured based on physical volume and stated in barrels (“MBbl”).

Natural Gas Gathering and Processing. The following table sets forth certain information regarding our natural gas gathering and processing assets as of or for the year ended December 31, 2016:

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Asset/Basin	Approximate Length (miles)	Approximate Compression (Horsepower)	Average Gathered Volume (TBtu/d)	Number of Processing Plants	Processing Capacity (MMcf/d)	NGLs Produced (MBbl/d)	Gross Acreage Dedications (in millions)
Anadarko Basin	8,000	710,900	1.65	11	1,845	65.19	4.8
Arkoma Basin	2,900	134,500	0.62	1	60	4.86	1.4
Ark-La-Tex Basin[1]	1,700	146,700	0.86	2	545	8.65	0.7
Total	12,600	992,100	3.13	14	2,450	78.70	6.9

(1) Ark-La-Tex Basin assets also include 14,500 Bbl/d of fractionation capacity and 6,300 Bbl/d of ethane pipeline capacity, which are not listed in the table.

Our gathering assets include more than 12,600 miles of natural gas gathering pipelines as of December 31, 2016. Our natural gas gathering systems consist of networks of pipelines that collect natural gas from points at or near our customers' wells for delivery to plants for processing or pipelines for transportation. Natural gas is moved from the receipt points to the delivery points on our gathering systems by the use of compression.

Our natural gas processing assets included 14 natural gas processing plants with 2,450 MMcf/d of inlet capacity as of December 31, 2016. Natural gas is comprised primarily of methane, but at the wellhead natural gas may contain varying amounts of NGLs. Our processing plants recover NGLs from natural gas and primarily deliver NGLs and natural gas to pipelines for transportation. The following table sets forth information with respect to our natural gas processing plants as of or for the year ended December 31, 2016:

Processing Plant	Year Installed		Type of Plant	Average Daily Inlet Volumes (MMcf/d)	Inlet Capacity (MMcf/d)	NGL Production Capacity (Bbl/d)[1]
Anadarko						
Bradley II	2016		Cryogenic	65	200	28,000
Bradley	2015		Cryogenic	191	200	28,000
McClure	2013		Cryogenic	182	200	22,000
Wheeler	2012		Cryogenic	179	200	22,000
South Canadian	2011		Cryogenic	188	200	26,000
Clinton	2009		Cryogenic	124	120	14,000
Roger Mills	2008		Refrigeration	25	100	—
Canute	1996		Cryogenic	32	60	4,300
Cox City	1994		Cryogenic	118	180	14,500
Thomas	1981		Cryogenic	59	135	9,900
Calumet	1969		Lean Oil	68	250	8,000
Arkoma						
Wetumka	1983		Cryogenic	33	60	5,000
Ark-La-Tex						
Sligo[2]	2004		Refrigeration	31	225	1,400
Waskom	1995	[3]	Cryogenic	182	320	14,500
Total				1,477	2,450	197,600

(1) Excludes condensate capacity.

(2) Average daily inlet volumes and inlet capacity includes 18 MMcf/d and 25 MMcf/d, respectively, related to a separate cryogenic unit.

(3) A processing plant has been in operation on the Waskom plant site since 1940. The Waskom plant was upgraded to cryogenic in 1995.

The natural gas gathering and processing assets in the Anadarko Basin include 11 processing plants, nine of which are interconnected through our super-header system. The super-header system is configured to facilitate the flow of natural gas across our operating areas in western Oklahoma and the Texas Panhandle to the Bradley, Bradley II, Cox City, Thomas, McClure, Calumet,

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Clinton, South Canadian and Wheeler processing plants. The super-header system allows us to optimize the utilization of the connected processing plants.

Crude Oil Gathering. As of December 31, 2016, we had approximately 175 miles of crude oil gathering pipelines and approximately 160 miles of produced water gathering pipelines in the Bakken Shale of the Williston Basin. Our crude oil gathering systems have a combined design capacity of 49.5 MBbl/d, and as of December 31, 2016, we had 0.2 million gross acres dedicated under a crude oil gathering agreement. For the year ended December 31, 2016, we had an average daily throughput of 25.0 MBbl/d of crude oil and an average daily throughput of 6.0 MBbl/d of produced water on our Bakken Shale gathering system.

Our Bakken Shale crude oil gathering assets are located in Dunn, McKenzie, Williams and Mountrail Counties in North Dakota. These systems were designed and built to serve the crude oil production of XTO in the area that they serve. On our systems, crude oil is received on crude oil gathering pipelines near our customer’s wells for delivery to third party transportation pipelines, and produced water is received by produced water gathering pipelines for delivery to third party disposal wells. We do not take title to crude oil or produced water gathered and we do not own or operate produced water disposal wells.

Delivery Points. Natural gas that is gathered, and when applicable, processed, is typically redelivered to our customers at interconnections with transportation pipelines. Our gathering lines interconnect with both our interstate and intrastate pipelines, as well as other interstate and intrastate pipelines, including the Acadian, ANR, ETC Tiger, Gulf Crossing, Gulf South, NGPL, Northern Natural, Panhandle Eastern, Regency, Southern Natural Gas, Tennessee Gas and Texas Eastern Transmission pipelines. These connections provide producers with access to a variety of natural gas market hubs.

Crude oil gathered on our Bakken Shale gathering systems in Dunn and McKenzie Counties is redelivered to our customers on the BakkenLink Pipeline, which provides access to rail transportation. Crude oil gathered on our Bakken Shale gathering systems in Williams and Mountrail Counties is redelivered to our customers on the Enbridge North Dakota Pipeline, which provides interstate transportation from North Dakota to Minnesota. We anticipate constructing interconnections between our gathering systems and other pipelines that will provide access to the Dakota Access Pipeline during 2017.

We typically purchase the NGLs produced at our processing plants, and most of the NGLs are delivered into third-party pipelines and transported to Conway, Kansas, or Mont Belvieu, Texas, where the NGLs are sold under contract or on the spot market. At our Cox City, Calumet and Wetumka plants, we operate depropanizers that allow us to extract propane from the NGL stream and sell propane to local markets. Additionally, we operate a fractionator at our Waskom plant and sell ethane, propane, butane and natural gasoline to local markets.

Customers. We generate revenues from producers in the basins in which we operate. For the year ended December 31, 2016, our top natural gas gathering and processing customers by gathered volumes were Continental Resources, Inc. (Continental), Vine Oil and Gas (Vine), GeoSouthern Energy Corporation (GeoSouthern), XTO, Apache Corporation (Apache), Tapstone Energy LLC (Tapstone), affiliates of Chesapeake Energy Corporation (Chesapeake), BP America Production Company (BP), Covey Park Energy LLC (Covey Park) and Marathon Oil Company (Marathon). For the year ended December 31, 2016, our top ten natural gas producer customers accounted for approximately 66% of our gathered natural gas volumes.

Our Bakken Shale gathering systems serve XTO. The rates and terms of service on our Bakken Shale crude oil gathering systems are regulated by FERC under the Interstate Commerce Act, but our Bakken Shale produced water gathering systems are not FERC regulated. As of December 31, 2016, XTO was our only customer on these systems.

Contracts. Our contracts typically provide for natural gas and crude oil gathering services that are fee-based and for natural gas processing arrangements that are fee-based, or percent-of-liquids, percent-of-proceeds or keep-whole based. For the year ended December 31, 2016, 46%, 46% and 8% of our inlet volumes were under processing arrangements that were fee-based, percent-of-proceeds or percent-of-liquids, and keep-whole, respectively. For the year ended December 31, 2016, 78% of our gathering and processing gross margin was fee-based, and the remaining 22% of our gathering and processing gross margin was primarily from sales of commodities, including natural gas, natural gas liquids and condensate received under percent-of-proceeds, percent-of-liquids and keep-whole arrangements.

In lean gas areas, such as the lean gas areas of the eastern Arkoma Basin and the Haynesville Shale of the Ark-La-Tex Basin, some of our natural gas gathering contracts contain minimum volume commitments from our customers. In addition, a portion of the crude oil gathered by our crude oil gathering system is under a contract with a minimum volume commitment. Under a minimum volume commitment a customer agrees to either deliver a minimum volume of natural gas or crude oil to our system for service or pay the service fees for the minimum volume of natural gas or crude oil regardless of whether or not the minimum volume of natural gas or crude oil is delivered. We call any payment for the difference between the volume gathered and the minimum volume committed a shortfall payment. Some of our contracts provide our customers the option to elect to pay a higher gathering fee over

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the remaining term of the contract in lieu of making a shortfall payment. For the year ended December 31, 2016, 31% of our gathering and processing gross margin was attributable to natural gas gathering contracts with minimum volume commitments, which as of December 31, 2016 had volume commitment-weighted average remaining terms of 4.6 years. Of this gross margin, 62% was attributable to shortfall payments. For the year ended December 31, 2016, 3% of our gathering and processing gross margin was attributable to a crude oil gathering contract with a minimum volume commitment and a remaining term of 12.2 years; however, if the customer ships in excess of the minimum volume, this volume commitment could end before the expiration of the contract term. Of this gross margin, none was attributable to shortfall payments.

For our gathering and processing contracts that do not have minimum volume commitments, we strive to obtain acreage dedications. Under an acreage dedication, a customer agrees to deliver all of the natural gas or crude oil produced from a given area to our system for gathering, and, if applicable, processing. As of December 31, 2016, we had 6.9 million gross acres dedicated under natural gas gathering agreements with a volume-weighted average remaining term of 5.9 years, and 0.2 million gross acres dedicated under a crude oil gathering agreement with a remaining term of 14.2 years.

Construction. Our gathering and processing business involves the construction of natural gas and crude oil gathering and natural gas processing assets as needed to serve our existing and new customers. For example, during the year ended December 31, 2016, we constructed 200 miles of gathering pipelines, added 15,700 horsepower of compression and invested $268 million in the construction of gathering and processing assets. The Bradley II Plant, a cryogenic processing facility, was placed in service in the second quarter of 2016 and began full commercial operations in July 2016. In addition, in the second quarter of 2016, we elected to delay the completion of the Wildhorse Plant, a cryogenic processing facility that we plan to connect to our super-header system in Garvin County, Oklahoma. As of December 31, 2016, we anticipate that it would take at least 12 months to complete the construction of the Wildhorse plant following the restart of construction.

Competition. Competition to gather and process natural gas is primarily a function of gathering rate, processing value, system reliability, fuel rate, system run time, construction cycle time and prices at the wellhead. Our gathering and processing systems compete with gatherers and processors of all types and sizes, including those affiliated with various producers, other major pipeline companies and various independent midstream entities. In the process of selling NGLs, we compete against other natural gas processors extracting and selling NGLs. Our primary competitors are other midstream companies who are active in the regions where we operate.

Competition to gather crude oil and produced water is primarily a function of rates, terms of service, system reliability, construction cycle time and prices at the wellhead. The rates and terms of service of our crude oil gathering, but not our produced water gathering, are FERC regulated. Our Bakken gathering systems compete with other gatherers, including those affiliated with producers and other midstream companies.

Seasonality. While the results of our gathering and processing segment are not materially affected by seasonality, from time to time our operations and construction of assets can be impacted by inclement weather.

Transportation and Storage

We own and operate interstate and intrastate transportation and storage systems across nine states. Our transportation and storage systems consist primarily of our interstate systems, EGT and MRT, our intrastate system, EOIT, and our investment in SESH. Our transportation and storage assets transport natural gas from areas of production and interconnected pipelines to power plants, LDCs and industrial end users as well as interconnected pipelines for delivery to additional markets. Our transportation and storage assets also provide facilities where natural gas can be stored by customers.

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The following table sets forth certain information regarding our transportation and storage assets as of or for the year ended December 31, 2016:
Transportation and Storage

Asset	Length (miles)	Compression (Horsepower)	Average Throughput (TBtu/d)	Transportation Capacity (Bcf/d) (1)	Transportation Firm Contracted Capacity (Bcf/d)	Storage Capacity (Bcf)	Storage Firm Contracted Capacity (Bcf/d)
EGT	5,900	381,900	2.5	6.5	5.42	29.5	22.92
MRT	1,600	118,600	0.7	1.7	1.62	31.5	28.77
EOIT	2,200	216,200	1.7 (2)	— (2)	—	24.0	12.25
Subtotal	9,700	716,700	4.9	8.2	7.04	85.0	63.94
SESH	290	107,800	—	1.1 (3)	—	—	—
Total	9,990	824,500	4.9	9.3	7.04	85.0	63.94

(1) Actual volumes transported per day may be less than total firm contracted capacity based on demand.

(2) Our EOIT pipeline system is a web-like configuration with multidirectional flow capabilities between numerous receipt and delivery points, which limits our ability to determine an overall system capacity. During the year ended December 31, 2016, the peak daily throughput was 2.3 TBtu/d or, on a volumetric basis, 2.3 Bcf/d.

(3) SESH has 1.09 Bcf/d of transportation capacity from Perryville, Louisiana to its endpoint in Mobile County, Alabama.

Our transportation and storage assets were designed and built to serve large natural gas and electric utilities in our areas of operation. In addition, our transportation and storage assets serve natural gas producers, industrial end users and natural gas marketers. For the year ended December 31, 2016, our top transportation and storage customers by revenue were affiliates of CenterPoint Energy, Spire Inc. (Spire), XTO, American Electric Power Co. (AEP), OGE Energy, Continental, Chesapeake, Midcontinent Express Pipeline LLC (MEP), EOG Resources, Inc. (EOG) and Entergy Corporation (Entergy).

Our transportation assets include approximately 10,000 miles of transportation pipelines in Texas, Oklahoma, Arkansas, Louisiana, Kansas and Missouri, providing access to natural gas supplies from the Anadarko, Arkoma and Ark-La-Tex Basins to natural gas consuming markets in the Southeastern, Northeastern and Midwestern United States. Our storage assets, as of December 31, 2016, provide a combined capacity of 85.0 Bcf with 2.0 Bcf/d of aggregate maximum withdrawal capacity from our seven storage facilities in Oklahoma, Louisiana and Illinois and from our undivided 1/12th interest in the Bistineau Storage Facility in Louisiana. Gulf South owns an undivided 9/12th interest in, and operates, the Bistineau Storage Facility. In addition, we have contracted for 3.3 Bcf of firm storage capacity in Cardinal’s Perryville and Arcadia salt cavern storage facilities.

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Our transportation and storage assets are comprised of three categories: (1) interstate transportation and storage, (2) intrastate transportation and storage and (3) our investment in SESH.

Please see “Note 18. Reportable Business Segments included in Item 8. Financial Statements and Supplementary Data—Notes to Audited Consolidated Financial Statements” for transportation and storage segment information related to Total Revenues, Operating Income and Total Assets.

Interstate Transportation and Storage

Our interstate transportation and storage business consists of EGT and MRT. As interstate pipelines, EGT and MRT are subject to regulation as natural gas companies by FERC under the NGA.

EGT

EGT provides natural gas transportation and storage services primarily to customers in Oklahoma, Texas, Arkansas, Louisiana, Missouri and Kansas. In addition to 5,900 miles of interstate pipelines with capacity of 6.5 Bcf/d, EGT has two underground natural gas storage facilities in Oklahoma and one underground natural gas storage facility in Louisiana, which, as of December 31, 2016, operate at a combined capacity of 29.5 Bcf with 739 MMcf/d of aggregate maximum withdrawal capacity.

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Interconnections and Delivery Points. In addition to delivering natural gas to utilities and industrial end users in Oklahoma, Louisiana, Texas and Arkansas, EGT receives natural gas from and delivers natural gas to a variety of intrastate and interstate pipelines through its numerous interconnections. Those interconnections include SESH, ANR, Columbia Gulf, EOIT, Gulf South, MEP, MRT, SONAT, Tennessee Gas, Texas Eastern, Texas Gas and Trunkline. Through EGT's interconnection with SESH, our customers have access to the Southeast power generation market. Through our interconnections with other pipelines, our customers have access to the Midwest and Northeast markets. Many of EGT's interconnections are at our Perryville Hub, which provides the ability to move natural gas between 11 major interstate pipelines. As a result, EGT provides our customers with access to not only natural gas consuming markets in Oklahoma, Louisiana, Texas and Arkansas, but also most of the major natural gas consuming markets east of the Mississippi River. In addition, EGT provides our customers supplying those markets with access to natural gas from producing basins and shale plays across the Mid-continent, including the Anadarko, Arkoma and Ark-La-Tex basins and the Barnett, Fayetteville, Granite Wash, Haynesville, SCOOP and STACK plays.

Customers. EGT primarily serves LDCs owned by CenterPoint Energy, producers in key plays in the Mid-continent, power plants, other LDCs and industrial end-users. EGT's customer are primarily located in Arkansas, Louisiana, Oklahoma and Texas. For the year ended December 31, 2016, approximately 25% of EGT's service revenue was attributable to contracts with LDCs owned by CenterPoint Energy with a volume-weighted average contract life of 4.1 years. In addition to the CenterPoint LDCs, EGT's other major customers include XTO, Continental and AEP.

Contracts. Although EGT has established maximum rates for interstate transportation and storage services as required by FERC, EGT is authorized to enter into negotiated rate and discounted rate agreements with its customers. EGT's services are typically provided under firm, fee-based transportation and storage agreements. For the year ended December 31, 2016, approximately 59% of our transportation and storage gross margin was derived from EGT's firm contracts, 83% of EGT's transportation capacity was under firm contracts with a volume-weighted average remaining contract life of 2.8 years, and 78% of EGT's storage capacity was under firm contracts with a volume-weighted average remaining contract life of 4.2 years. The primary terms of EGT's firm transportation and storage contracts with the CenterPoint Energy LDCs will begin to expire in 2018, with the majority of the contracts expiring in 2021.

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Seasonality. EGT provides gas transmission delivery services to LDCs owned by CenterPoint in Arkansas, Louisiana, Oklahoma and Texas. Customer demand for natural gas on EGT is usually greater during the winter, primarily due to LDC demand to serve residential and commercial natural gas requirements. In addition, EGT experiences seasonal impacts associated with storage spreads and basis spreads on interconnected pipelines, as well as power plant demand.

Competition. EGT competes with a variety of other interstate and intrastate pipelines across Texas, Oklahoma, Arkansas and Louisiana. Our management views the principal elements of competition among pipelines as rates and terms, flexibility and reliability of service. EGT provides both flexibility and reliability of service with access to multiple sources of supply in the Anadarko, Arkoma and Ark-La-Tex Basins and access to multiple markets in the Midwest, Northeast and Southeast through interconnections with other pipelines. EGT’s interconnections with other pipelines are primarily at our Perryville Hub.

MRT

MRT provides natural gas transportation and storage services principally in Texas, Arkansas, Louisiana, Missouri and Illinois. In addition to 1,600-miles of interstate pipelines with capacity of 1.7 Bcf/d, MRT has one underground natural gas storage facility in Louisiana and one underground natural gas storage facility in Illinois, which, as of December 31, 2016, operate at a combined capacity of 31.5 Bcf with 620 MMcf/d of aggregate maximum withdrawal capacity.

Interconnections and Delivery Points. MRT receives natural gas from a variety of interstate and intrastate pipelines through its interconnections and delivers natural gas to the St. Louis market. Those interconnections include EGT, Gulf South, NGPL, Ozark Gas Transmission, Texas Eastern, Texas Gas and Trunkline. From MRT’s West Line, we provide our customers with access to supply from East Texas and North Louisiana, including the Haynesville Shale. From MRT’s mainline, we provide our customers with access to supply from the Anadarko, Arkoma and Ark-La-Tex basins through the Perryville Hub and from and the Fayetteville Shale though our interconnection with Ozark Gas Transmission. From MRT’s East Line, we provide our customers with access to supply from the Mid-continent and the Marcellus Shale through our interconnections with NGPL and Trunkline. As a result, MRT provides the St. Louis market with access to natural gas from a variety of major producing basins across the U.S.

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Customers. MRT primarily serves Laclede Gas Company, the St. Louis LDC owned by Spire. For the year ended December 31, 2016, 59% of MRT's service revenue was attributable to Spire under contracts with a volume-weighted average contract life of 2.3 years. MRT's other customers include utilities and industrial end users. MRT's customers are primarily located in Arkansas, Missouri and Illinois.

Contracts. MRT's services are typically provided under firm, fee-based transportation and storage agreements, with rates and terms of service regulated by FERC. For the year ended December 31, 2016, approximately 14% of our transportation and storage gross margin was derived from MRT's firm contracts, 95% of MRT's transportation capacity was under firm contracts with a volume-weighted average remaining contract life of 2.5 years and 91% of MRT's storage capacity was under firm contracts with a volume-weighted average remaining contract life of 1.4 years. MRT's firm transportation and storage contracts with Spire are scheduled to expire in 2018 and 2020.

Seasonality. Customer demand for natural gas on MRT is usually greater during the winter, primarily due to LDC demand to serve residential and commercial natural gas requirements. In addition, MRT experiences seasonal impacts associated with storage spreads and basis spreads on market-based pipelines.

Competition. MRT competes with various intrastate pipelines providing natural gas to the St. Louis market. In addition, MRT, from time-to-time, competes with potential projects to connect one or more third party interstate pipelines to the St. Louis market, such as the proposed Spire STL Pipeline for which a notice of application was filed on February 6, 2017 with FERC. Our management views the principal elements of competition among pipelines as rates, terms of service, flexibility and reliability of service. MRT, through its interconnections with a variety of interstate and intrastate pipelines and its access to supply from a variety of producing basins, provides our customers with access to a variety of natural gas supply sources.

Intrastate Transportation and Storage

Our intrastate transportation and storage assets consist primarily of EOIT. EOIT provides transportation and storage services in Oklahoma. Our EOIT system delivers natural gas from the Arkoma and Anadarko Basins, including growth areas in the Cana Woodford, Granite Wash, Cleveland, Tonkawa, SCOOP, STACK and Mississippi Lime Shale plays in western Oklahoma and the Texas Panhandle, to utilities and industrial end users connected to EOIT and to interstate and intrastate pipelines interconnected with EOIT. EOIT had 1.72 TBtu/d of average daily throughput for the year ended December 31, 2016. In addition to 2,200 miles of intrastate pipelines, EOIT has two underground natural gas storage facilities in Oklahoma, which, as of December 31, 2016 operate at a combined capacity of 24 Bcf with 605 MMcf/d of aggregate maximum withdrawal capacity. Our intrastate transportation also includes a 20-mile intrastate pipeline in Illinois.

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Interconnections and Delivery Points. EOIT has 67 interconnections and EOIT interconnects with EGT and 12 third-party interstate and intrastate natural gas pipelines, including ANR Pipeline, El Paso Natural Gas Pipeline, Gulf Crossing Pipeline Company LLC, MEP, Natural Gas Pipeline Company of America, Northern Natural Gas Company, ONEOK Gas Transmission, Ozark Gas Transmission, L.L.C., Panhandle Eastern Pipe Line, Postrock KPC Pipeline, LLC, Southern Star Central Gas Pipeline and Western Trails. In addition, EOIT connects to 41 end-user customers, including 16 natural gas-fired electric generation facilities in Oklahoma.

Customers. EOIT’s customers include Oklahoma’s two largest electric utilities, OG&E and Public Service Company of Oklahoma, an affiliate of AEP (PSO). For the year ended December 31, 2016, approximately 7% of our total transportation and storage gross margin was attributable to a firm contract with our affiliate OG&E, and approximately 3% of our transportation and storage gross margin was attributable to a firm contract with PSO. Our transportation agreement with OG&E extends through April 30, 2019, and will remain in effect year to year thereafter unless either party provides notice of termination to the other party at least 180 days prior to the commencement of the succeeding annual period. Our transportation agreement with PSO is on a one-year renewal term and has been extended through December 31, 2017. EOIT’s customers also include other electric generators, LDCs, Arkoma and Anadarko Basin producers and industrial end users.

Contracts. EOIT provides fee-based firm and interruptible transportation and storage services on both an intrastate basis and, pursuant to Section 311 of the NGPA, on an interstate basis. For the year ended December 31, 2016, approximately 20% of our transportation and storage gross margin was derived from EOIT’s firm contracts, with a volume-weighted average remaining contract life of 4.9 years.

Seasonality. EOIT provides gas transmission delivery services to the majority of OG&E’s and all of PSO’s natural gas-fired electric generation facilities in Oklahoma. Customer demand for natural gas transportation and storage services on EOIT is usually greater during the summer, primarily due to demand by natural gas-fired power plants to serve residential and commercial electricity requirements.

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Competition. EOIT competes with a variety of interstate and intrastate pipelines in providing transportation and storage services in Oklahoma, including competing against several pipelines with which EOIT interconnects. We view competition in the transportation and storage market as primarily a function of rates, terms of services, flexibility and reliability of service. EOIT's integrated transportation and storage system allows us to provide load following service to natural gas-fired power plants to allow the power plants the ability to regulate generation and meet the instantaneous changes in customer demand for electricity.

Our Investment in SESH

SESH is an approximately 290-mile interstate pipeline that provides transportation services in Louisiana, Mississippi and Alabama. We own a 50% interest in SESH and provide field operations for the pipeline. Spectra Energy Partners, LP owns the remaining 50% interest in SESH and provides gas control and commercial operations for the pipeline. As of December 31, 2016, SESH had 1.09 Bcf/d of transportation capacity from Perryville, Louisiana to its endpoint in Mobile County, Alabama.

Interconnections and Delivery Points. SESH runs from the Perryville Hub in northeastern Louisiana to southwestern Alabama near the Gulf Coast. SESH has 20 interconnects with third-party natural gas pipelines and provides access to major Southeast and Northeast markets. Natural gas transported by SESH is primarily transported by the interconnecting pipelines to companies generating electricity for the Florida power market. SESH also interconnects with three high-deliverability storage facilities, Mississippi Hub Storage, Petal Gas Storage and Southern Pines Energy Center.

Customers and Contracts. SESH's customers are companies that generate electricity for the Florida power market. The rates charged by SESH for interstate transportation services are regulated by FERC. SESH's transportation services are typically provided under firm, fee-based negotiated rate agreements. SESH's transportation contracts have a volume-weighted average remaining contract life of 5.4 years.

Seasonality. SESH is generally not impacted by seasonality. SESH's load factor generally remains constant throughout the year.

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Competition. SESH competes with other interstate and intrastate pipelines providing access to the Southeast power generation market. Our management views the principal elements of competition among pipelines as rates and terms, flexibility and reliability of service.

Rate and Other Regulation

Federal, state and local regulation of pipeline gathering and transportation services may affect certain aspects of our business and the market for our products and services.

Interstate Natural Gas Pipeline Regulation

EGT, MRT and SESH are subject to regulation by FERC and are considered "natural gas companies" under the Natural Gas Act ("NGA"). Natural gas companies may not charge rates that have been determined to be unjust or unreasonable by FERC. In addition, the NGA prohibits natural gas companies from granting any undue preference or advantage, or unduly discriminating against any person with respect to pipeline rates or terms and conditions of service, including unduly discriminatory or preferential access to information. FERC authority over natural gas companies that provide natural gas pipeline transportation services in interstate commerce includes:

- rates, terms and conditions of service and service contracts;
- certification and construction of new facilities or expansion of existing facilities;
- abandonment of facilities;
- maintenance of accounts and records;
- acquisition and disposition of facilities;
- initiation, extension or abandonment of services;
- accounting, depreciation and amortization policies;
- conduct and relationship with certain affiliates;
- market manipulation in connection with the purchase or sale of natural gas or transportation in interstate commerce; and
- various other matters.

Under the NGA, the rates for service on interstate facilities must be just and reasonable and not unduly discriminatory. Generally, the maximum recourse rates for interstate pipelines are based on the pipeline's cost of service including recovery of and a return on the pipeline's actual prudent investment cost. Key determinants in the ratemaking process are the total costs of providing service, allowed rate of return and throughput projections. Our interstate pipeline operations may be affected by changes in the demand for natural gas, the available supply and relative price of natural gas in the Mid-continent and Gulf Coast natural gas supply regions and general economic conditions.

Rate and tariff changes can only be implemented upon approval by FERC. Two primary methods are available for changing the rates, terms and conditions of service of an interstate natural gas pipeline. Under the first method, the pipeline voluntarily seeks a rate or tariff change by making a filing with FERC justifying the proposed change. FERC provides notice of the proposed change to the public through publication on its website and in the Federal Register. If FERC determines that a proposed change is just and reasonable, FERC grants approval of and allows the pipeline to implement the change. If FERC determines that a proposed change may not be just and reasonable, FERC may suspend the proposed change for up to five months. Subsequent to any suspension period ordered by FERC, the proposed change may be placed into effect by the company, pending final FERC approval. In most cases, a proposed rate change is placed into effect before a final FERC determination on such rate change, and the pipeline is permitted to collect the proposed rate subject to refund (plus interest). Under the second method, FERC may, on its own motion or based on a complaint filed by a third party, initiate a proceeding seeking to compel the company to change its rates, terms and/or conditions of service. If FERC determines that the existing rates, terms and/or conditions of service are unjust, unreasonable, unduly discriminatory or preferential, then any rate reduction or change that it orders generally will be effective prospectively from the date of the FERC order requiring this change.

Market Behavior Rules; Posting and Reporting Requirements

On August 8, 2005, Congress enacted the EPAct of 2005. Among other matters, the EPAct of 2005 amended the NGA to add an anti-manipulation provision that makes it unlawful for any entity to engage in prohibited behavior in contravention of rules and regulation to be prescribed by FERC and, furthermore, provides FERC with additional civil penalty authority. On January 19,

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2006, FERC issued Order No. 670, a rule implementing the anti-manipulation provisions of the EPAct of 2005. The rules make it unlawful for any entity, directly or indirectly in connection with the purchase or sale of natural gas subject to the jurisdiction of FERC or the purchase or sale of transportation services subject to the jurisdiction of FERC, to (1) use or employ any device, scheme or artifice to defraud; (2) to make any untrue statement of material fact or omit to make any such statement necessary to make the statements not misleading; or (3) to engage in any act or practice that operates as a fraud or deceit upon any person. The anti-manipulation rules apply to interstate gas pipelines and storage companies and intrastate gas pipelines and storage companies that provide interstate services, such as Section 311 service, as well as otherwise non-jurisdictional entities to the extent the activities are conducted "in connection with" gas sales, purchases or transportation subject to FERC jurisdiction. The anti-manipulation rules do not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering to the extent such transactions do not have a "nexus" to jurisdictional transactions. The EPAct of 2005 also amends the NGA and the NGPA to give FERC authority to impose civil penalties for violations of these statutes and FERC's regulations, rules and orders, up to $1 million per day per violation for violations occurring after August 8, 2005. The maximum penalty was increased to approximately $1.2 million on July 6, 2016. In connection with this enhanced civil penalty authority, FERC issued a revised policy statement on enforcement to provide guidance regarding the enforcement of the statutes, orders, rules and regulations it administers, including factors to be considered in determining the appropriate enforcement action to be taken. If we fail to comply with all applicable FERC-administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines. In addition, the CFTC is directed under the Commodities Exchange Act, or CEA, to prevent price manipulations for the commodity and futures markets, including the energy futures markets. Pursuant to the Dodd-Frank Act and other authority, the CFTC has adopted anti-market manipulation regulations that prohibit fraud and price manipulation in the commodity and futures markets. The CFTC also has statutory authority to seek civil penalties of up to the greater of $1.1 million or triple the monetary gain to the violator for violations of the anti-market manipulation sections of the CEA.

The EPAct of 2005 also added Section 23 to the NGA, authorizing FERC to facilitate price transparency in markets for the sale or transportation of physical natural gas in interstate commerce. In 2007, FERC took steps to enhance its market oversight and monitoring of the natural gas industry by issuing several rulemaking orders designed to promote gas price transparency and to prevent market manipulation. In December 2007, FERC issued a final rule on the annual natural gas transaction reporting requirements, as amended by subsequent order on rehearing, or Order No. 704. Order No. 704 requires buyers and sellers of annual quantities of natural gas of 2,200,000 MMBtu or more, including entities not otherwise subject to FERC's jurisdiction, to provide by May 1 of each year an annual report to FERC describing their aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year to the extent such transactions utilize, contribute to or may contribute to the formation of price indices. Order No. 704 also requires market participants to indicate whether they report prices to any index publishers and, if so, whether their reporting complies with FERC's policy statement on price reporting. In June 2010, FERC issued the last of its three orders on rehearing and clarification further clarifying its requirements.

Intrastate Natural Gas Pipeline and Storage Regulation

Our intrastate natural gas pipeline and Hinshaw pipelines are subject to state regulation of rates and terms of service, but the scope of such regulation varies state to state. In Oklahoma, our intrastate pipeline system (EOIT) is subject to limited regulation by the Oklahoma Corporation Commission, or the OCC. Oklahoma has a non-discriminatory access requirement, which is subject to a complaint-based review. EOIT's rates and terms of service are not subject to regulation by the OCC. In Illinois, our intrastate pipeline system is subject to regulation by the Illinois Commerce Commission.

Intrastate natural gas transportation is largely regulated by the state in which the transportation takes place. An intrastate natural gas pipeline system may transport natural gas in interstate commerce provided that the rates, terms and conditions of such transportation service comply with FERC's regulations under Section 311 of the NGPA and

Part 284 of the FERC's regulations. The NGPA regulates, among other things, the provision of transportation and storage services by an intrastate natural gas pipeline on behalf of an interstate natural gas pipeline or a LDC served by an interstate natural gas pipeline. Under Section 311, rates charged for transportation must be fair and equitable, and amounts collected in excess of fair and equitable rates are subject to refund with interest. The rates under Section 311 are maximum rates and an intrastate pipeline may agree to discount contractual rates at or below such maximum rates. Rates for service pursuant to Section 311 of the NGPA are generally subject to review and approval by FERC at least once every five years. Should the FERC determine not to authorize rates equal to or greater than our currently approved Section 311 rates, our business may be adversely affected.

Failure to observe the service limitations applicable to transportation services provided under Section 311, failure to comply with the rates approved by FERC for Section 311 service, or failure to comply with the terms and conditions of service established in the pipeline's FERC-approved Statement of Operating Conditions could result in the assertion of federal NGA jurisdiction by FERC and/or the imposition of administrative, civil and criminal penalties, as described in the "—Interstate Natural Gas Pipeline Regulation" section above.

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The transportation rates charged by EOIT for natural gas transportation in interstate commerce on intrastate pipelines are subject to the jurisdiction of FERC under Section 311 of the NGPA. EOIT currently has two zones under its Section 311 transportation rate structure—an East Zone and a West Zone. For Section 311 service, EOIT may charge up to its maximum established zonal East and West interruptible transportation rates for interruptible transportation in one zone or cumulative maximum rates for transportation in both zones. EOIT may charge up to its maximum established firm rate for firm Section 311 transportation in its East and West Zones. Finally, EOIT may charge the applicable fixed zonal fuel percentage(s) for the fuel used in transporting natural gas under Section 311 on our system. The fixed zonal fuel percentages are the same for firm and interruptible Section 311 services.

We also have a pipeline in Illinois that is subject to regulation by the Illinois Commerce Commission as a "Hinshaw pipeline." Under Section 1(c) of the NGA, a Hinshaw pipeline is exempt from FERC's NGA regulation if its operations are within a single state, if any gas received from interstate sources is received within the state and if its service is regulated by the state commission. A Hinshaw pipeline may, and our Illinois pipeline does, provide services in interstate commerce pursuant to limited jurisdiction certificate authority under Section 284.224(c) of FERC's regulations, thereby subjecting itself to the same type of limited FERC jurisdiction imposed on intrastate pipelines engaged in Section 311 service.

Under FERC Order No. 735, intrastate pipelines providing transportation services under Section 311 of the NGPA and Hinshaw pipelines operating under Section 1(c) of the NGA are required to report on a quarterly basis via FERC Form 549D more detailed information and storage transaction information, including: rates charged by the pipeline under each contract; receipt and delivery points and zones or segments covered by each contract; the quantity of natural gas the shipper is entitled to transport, store, or deliver; the duration of the contract; and whether there is an affiliate relationship between the pipeline and the shipper. Order No. 735 further requires that such information must be supplied through an electronic reporting system and will be posted on FERC's website, and that such quarterly reports may not contain information redacted as privileged. FERC promulgated this rule after determining that such transactional information would help shippers make more informed purchasing decisions and would improve the ability of both shippers and FERC to monitor actual transactions for evidence of market power or undue discrimination. Order No. 735 also extends FERC's periodic review of the rates charged by the subject pipelines from three to five years. In Order No. 735-A, FERC generally reaffirmed Order No. 735 requiring Section 311 and "Hinshaw" pipelines to report on a quarterly basis storage and transportation transactions containing specific information for each transaction, aggregated by contract. Our intrastate storage assets at the Wetumka Storage Field offer both fee-based firm and interruptible storage services under Section 311 of the NGPA pursuant to terms and conditions specified in our statement of operating conditions for gas storage at market-based rates. Our intrastate Stuart Storage Field currently is used exclusively to provide intrastate storage service, even though FERC previously authorized the use of that storage facility for Section 311 interstate service.

Natural Gas Gathering and Processing Regulation

Section 1(b) of the NGA exempts natural gas gathering and processing facilities from the jurisdiction of the FERC. Although the FERC has not made formal determinations with respect to all of our facilities we consider to be gathering facilities, management believes that our natural gas pipelines meet the traditional tests that the FERC has used to determine that a pipeline is a gathering pipeline and is therefore not subject to FERC's NGA jurisdiction. The distinction between FERC-regulated transmission services and federally unregulated gathering services, however, has been the subject of substantial litigation, and the FERC determines whether facilities are gathering facilities on a case-by-case basis, so the classification and regulation of our gathering facilities is subject to change based on future determinations by the FERC, the courts or Congress. If the FERC were to consider the status of an individual facility and determine that the facility and/or services provided by it are not exempt from FERC regulation under the NGA and that the facility provides interstate service, the rates for, and terms and conditions of, services provided by such facility would be subject to regulation by the FERC under the NGA or the NGPA. Such regulation could decrease

revenue, increase operating costs, and, depending upon the facility in question, could adversely affect our results of operations and cash flows. In addition, if any of our facilities were found to have provided services or otherwise operated in violation of the NGA or NGPA, this could result in the imposition of civil penalties as well as a requirement to disgorge charges collected for such service in excess of the rate established by the FERC.
States may regulate gathering pipelines. State regulation of gathering facilities generally includes various safety, environmental and, in some circumstances, requirements prohibiting undue discrimination, and in some instances complaint-based rate regulation. Our gathering operations may be subject to ratable take and common purchaser statutes in the states in which they operate. The ratable take statutes generally require gatherers to take, without undue discrimination, natural gas production that may be tendered to the gatherer for handling. Similarly, common purchaser statutes generally require gatherers to purchase without undue discrimination as to source of supply or producer. These statutes are designed to prohibit discrimination in favor of one producer over another producer or one source of supply over another source of supply. These statutes have the effect of restricting our right as an owner of gathering facilities to decide with whom we contract to purchase or transport natural gas.

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Our gathering operations could be adversely affected should they be subject in the future to the application of state or federal regulation of rates and services. Our gathering operations could also be subject to additional safety and operational regulations relating to the design, construction, testing, operation, replacement and maintenance of gathering facilities. Additional rules and legislation pertaining to these matters are considered or adopted from time to time. We cannot predict what effect, if any, such changes might have on its operations, but the industry could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes.

Sales of Natural Gas

The price at which we buy and sell natural gas currently is not subject to federal regulation and, for the most part, is not subject to state regulation. However, as noted above, with regard to our physical purchases and sales of these energy commodities, and any related hedging activities that we undertake, we are required to observe anti-market manipulation laws and related regulations enforced by FERC and/or the CFTC. Should we violate the anti-market manipulation laws and regulations, we could also be subject to related third party damage claims by, among others, market participants, sellers, royalty owners and taxing authorities.

Our sales of natural gas are affected by the availability, terms and cost of pipeline transportation. As noted above, the price and terms of access to pipeline transportation are subject to extensive federal and state regulation. FERC is continually proposing and implementing new rules and regulations affecting those segments of the natural gas industry, most notably interstate natural gas transmission companies that remain subject to FERC jurisdiction. These initiatives also may affect the intrastate transportation of natural gas under certain circumstances. The stated purpose of many of these regulatory changes is to promote competition among the various sectors of the natural gas industry. We cannot predict the ultimate impact of these regulatory changes on our natural gas marketing operations.

Crude Oil Gathering Regulation

Crude oil gathering pipelines that provide interstate transportation service may be regulated as common carriers by FERC under the ICA, the Energy Policy Act of 1992 and the rules and regulations promulgated under those laws. Enable Bakken Crude Services, LLC (“Enable Bakken”) owns and operates two transportation systems that transport crude oil in interstate commerce and are located in the Bakken producing region of North Dakota. The ICA and FERC regulations require that rates for interstate service pipelines that transport crude oil and refined petroleum products (collectively referred to as “petroleum pipelines”) and certain other liquids, be just and reasonable and are to be non-discriminatory or not confer any undue preference upon any shipper. FERC regulations also require interstate common carrier petroleum pipelines to file with FERC and publicly post tariffs stating their interstate transportation rates and terms and conditions of service. Under the ICA, FERC or interested persons may challenge existing or changed rates or services. The FERC is authorized to investigate such charges and may suspend the effectiveness of a new rate for up to seven months. A successful rate challenge could result in a common carrier paying refunds together with interest for the period that the rate was in effect. FERC may also order a pipeline to change its rates, and may require a common carrier to pay shippers reparations for damages sustained for a period up to two years prior to the filing of a complaint.

If our rate levels were investigated by FERC, the inquiry could result in a comparison of our rates to those charged by others or to an investigation of our costs, including:

- the overall cost of service, including operating costs and overhead;
- the allocation of overhead and other administrative and general expenses to the regulated entity;
- the appropriate capital structure to be utilized in calculating rates;
- the appropriate rate of return on equity and interest rates on debt;
- the rate base, including the proper starting rate base;

- the throughput underlying the rate; and
- the proper allowance for federal and state income taxes.

For some time now, FERC has been issuing regulatory assurances that necessarily balance the anti-discrimination and undue preference requirements of common carriage with the expectations of investors in new and expanding petroleum pipelines. There is an inherent tension between the requirements imposed upon a common carrier and the need for owners of petroleum pipelines to be able to enter into long-term, firm contracts with shippers willing to make the commitments which underpin such large capital investments. For example, FERC has found that shipper contract rates are not per se violations of the duty of non-discrimination, provided that such rates are available to all similarly-situated shippers. In the same vein, FERC has approved varying term commitments with tiered rate discounts on the basis that committed shippers were not similarly situated with uncommitted shippers and further that different types of committed shippers were not similarly situated with each other if their commitment level

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materially differed. FERC has also found that shippers making certain capacity commitments to the pipeline can take advantage of priority or firm service, which is service that is not subject to typical capacity allocation requirements, so long as any interested shipper has an equal opportunity to make such a commitment to the carrier. FERC's solution has been to allow carriers to hold an "open season" prior to the in-service date of pipeline, during which time interested shippers can make commitments to the proposed pipeline project. Throughput commitments from interested shippers during an open season can be for firm service or for non-firm service. Typically, such an open season is for a 30-day period, must be publicly announced, and culminates in interested parties entering into transportation agreements with the carrier. Under FERC precedent, a carrier typically may reserve up to 90% of available capacity for the provision of firm or priority service to shippers making a commitment. At least 10% of capacity ordinarily is reserved for uncommitted shippers, i.e., "walk-up" shippers.

Under the ICA, FERC does not have authority over the siting of oil transportation assets nor over the abandonment of facilities or services. Accordingly, no approval from FERC is necessary prior to placing a new petroleum pipeline project in operation. However, FERC highly encourages carriers to file a Petition for Declaratory Order (PDO) to seek regulatory assurances for key terms of service offered during an open season. As long as the shippers on our Bakken crude oil gathering system move oil in interstate commerce, our crude oil gathering system will not be regulated by the North Dakota Public Service Commission.

Safety and Health Regulation

Certain of our facilities are subject to pipeline safety regulations. PHMSA regulates safety requirements in the design, construction, operation and maintenance of jurisdictional natural gas and hazardous liquid pipeline facilities. All natural gas transmission facilities, such as our interstate natural gas pipelines, are subject to PHMSA's pipeline safety regulations, but natural gas gathering pipelines are subject to the pipeline safety regulations only to the extent they are classified as regulated gathering pipelines. In addition, several NGL pipeline facilities and crude oil pipeline facilities are regulated as hazardous liquids pipelines. Currently, each such NGL or crude oil facility is excepted from many of the requirements of PHMSA's regulations applicable to hazardous liquids pipelines based on the facility's location, product transported and/or the low stress level at which it operates.

Pursuant to the Natural Gas Pipeline Safety Act of 1968, or NGPSA, and the Hazardous Liquid Pipeline Safety Act of 1979, or HLPSA, as amended by the Pipeline Safety Act of 1992, or PSA, the Accountable Pipeline Safety and Partnership Act of 1996, or APSA, the Pipeline Safety Improvement Act of 2002, or PSIA, the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006, or the PIPES Act, and the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, or the 2011 Pipeline Safety Act, the DOT, through PHMSA, regulates pipeline safety and integrity. The NGPSA regulates safety requirements in the design, construction, operation and maintenance of gas pipeline facilities, while the PSIA establishes mandatory inspections for all U.S. oil and natural gas transmission pipelines in high-consequence areas, or HCAs.

NGL and crude oil pipelines are subject to regulation by PHMSA under the HLPSA which requires PHMSA to develop, prescribe, and enforce minimum federal safety standards for the transportation of hazardous liquids by pipeline, and comparable state statutes with respect to design, installation, testing, construction, operation, replacement and management of pipeline facilities. HLPSA covers petroleum and petroleum products, including NGLs and condensate, and requires any entity that owns or operates pipeline facilities to comply with such regulations, to permit access to and copying of records and to file certain reports and provide information as required by the United States Secretary of Transportation. These regulations include potential fines and penalties for violations. Management believes that we are in compliance in all material respects with these HLPSA regulations. The PSA added the environment to the list of statutory factors that must be considered in establishing safety standards for hazardous liquid pipelines, established safety standards for certain "regulated gathering lines," and mandated that regulations be issued to establish criteria for operators to use in identifying and inspecting pipelines located in HCAs, defined as those areas that are unusually sensitive to environmental damage, that cross a navigable waterway, or that have a high population density. In 1996, Congress enacted the APSA, which limited the operator identification requirement to operators of pipelines that cross a waterway where a substantial likelihood of commercial navigation exists, required that certain areas where a pipeline rupture would likely cause permanent or long-term environmental damage be considered in determining whether an area is unusually sensitive to environmental damage, and mandated that regulations be issued for the qualification and testing of certain pipeline personnel. In the PIPES Act, Congress required mandatory inspections for certain U.S. crude oil and natural gas transmission pipelines in HCAs and mandated that regulations be issued for low-stress hazardous liquid pipelines and pipeline control room management.

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PHMSA has developed regulations that require natural gas pipeline operators to implement integrity management programs, including more frequent inspections and other measures to ensure pipeline safety in HCAs. The regulations require operators, including us, to:
- perform ongoing assessments of pipeline integrity;
- identify and characterize applicable threats to pipeline segments that could impact an HCA;
- improve data collection, integration and analysis;
- repair and remediate pipelines as necessary; and
- implement preventive and mitigating actions.

Although many of our pipeline facilities fall within a class that is currently not subject to these integrity management requirements, we may incur significant costs and liabilities associated with repair, remediation, and preventive or mitigating measures associated with our non-exempt pipelines. Furthermore, PHMSA has taken actions recently that may impact the exempt status of some of our pipeline facilities. On April 8, 2016, PHMSA published a notice of proposed rulemaking (NPRM) that would amend existing integrity management requirements, expand assessment and repair requirements to pipelines in areas with medium population densities, and extend regulatory requirements to onshore gas gathering lines that are currently exempt. PHMSA issued, but has yet to publish, a similar rule for hazardous liquids pipelines on January 13, 2017. That rule extends regulatory reporting requirements to all liquid gathering lines, requires additional event-driven and periodic inspections, requires use of leak detection systems on all hazardous liquid pipelines, modifies repair criteria, and requires certain pipelines to eventually accommodate inline inspection tools. It is unclear when or if this rule will go into effect as, on January 20, 2017, the Trump Administration requested that all regulations that had been sent to the Office of the Federal Register, but not yet published, be immediately withdrawn for further review. In 2016, we incurred $32 million of capital expenditures and operating costs for pipeline integrity management. We currently estimate that we will incur capital expenditures and operating costs of up to $290 million from 2017 to 2021 in connection with pipeline integrity management to complete the testing required by existing DOT regulations and their state counterparts. The estimated capital expenditures and operating costs include our estimates for the assessment, remediation and prevention or other mitigation that may be determined to be necessary. At this time, we cannot predict the ultimate costs of our integrity management program and compliance with these regulations because those costs will depend on the number and extent of any repairs found to be necessary and the degree to which newly proposed pipeline safety regulations may apply to our pipeline systems. We will continue to assess, remediate and maintain the integrity of our pipelines. The results of these activities could cause us to incur significant and unanticipated capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operations of our pipelines. Additionally, should we fail to comply with DOT or comparable state regulations, we could be subject to penalties and fines. If future DOT pipeline integrity management regulations were to require that we expand our integrity managements program to currently unregulated pipelines, including gathering lines, our costs associated with compliance may have a material effect on our operations.

On December 20, 2016, the PHMSA issued a Notice of Proposed Violation (“NOPV”) and Proposed Compliance Order to EGT and MRT. The Notice was issued following inspection of our Operations and Maintenance and Integrity Management procedures and an inspection of our related records and facilities conducted on February 22, 2016 and November 17, 2016. The Notice included three proposed violations and a Proposed Compliance Order. No fines or penalties were proposed in the Notice. On January 26, 2017, we sent a response requesting clarification of one of the three proposed violations and of the Proposed Compliance Order addressing that violation, and are contesting another of the three proposed violations, asking that it be withdrawn or modified.

The 2011 Pipeline Safety Act reauthorizes funding for federal pipeline safety programs, increases penalties for safety violations, establishes additional safety requirements for newly constructed pipelines, and requires studies of certain safety issues that could result in the adoption of new regulatory requirements for existing pipelines. The 2011 Pipeline Safety Act, among other things, increases the maximum civil penalty for pipeline safety violations and directs the

Secretary of Transportation to promulgate rules or standards relating to expanded integrity management requirements, automatic or remote-controlled valve use, excess flow valve use, leak detection system installation and testing to confirm the material strength of pipe operating above 30% of specified minimum yield strength in HCAs. PHMSA adopted new rules increasing the maximum administrative civil penalties for violations of the pipeline safety laws and regulations after January 3, 2012. Those potential penalties have recently been adjusted for inflation and can be up to approximately $0.2 million per violation per day, with a maximum of approximately $2 million for a related series of violations. In 2011, PHMSA issued a final rule applying safety regulations to certain rural low-stress hazardous liquid pipelines that were not covered previously by some of its safety regulations. PHMSA also published advance notice of proposed rulemakings to solicit comments on the need for changes to its natural gas and liquid pipeline safety regulations, including changes to those rules that would apply to gathering lines and removal of an exemption for natural gas pipelines installed before 1970. In May 2012, PHMSA published an advisory bulletin stating that operators of gas and hazardous liquid pipeline facilities should verify records relating to operating specifications for maximum allowable operating pressure, MAOP, for gas pipelines and

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maximum operating pressure, or MOP, for hazardous liquid pipelines. For natural gas transmission pipelines located within Class 3 and Class 4 locations or in Class 1 and Class 2 locations in HCAs, PHMSA modified its annual report form to require operators to report the number of verified miles of pipeline on their systems. This report was due and filed in June 2013, and subsequently updated in March 2014. No MOP reporting requirements were imposed on operators of hazardous liquid pipeline for the 2012 calendar year reports. Our current practice is to continually monitor and update our records with respect to MAOP of our gas pipelines.

On March 17, 2016, PHMSA proposed natural gas pipeline safety standards that, if implemented, are expected to lower methane emissions. Further, on January 13, 2017, PHMSA issued a final rule amending its pipeline safety regulations for the design, construction, testing, operation, and maintenance of pipelines transporting hazardous liquids. The rule imposes stricter standards that, among other things, determine how operators repair aging and high-risk infrastructure and increase the frequency of tests that assess the conditions of pipelines. In addition, the final rule extends certain safety-related condition reporting requirements to all hazardous liquid gathering lines and requires periodic assessments of certain hazardous liquid transmission lines in non-HCAs. The effective date of this rulemaking is currently uncertain due to a regulatory freeze implemented by the Trump administration on January 20, 2017. Future PHMSA rulemakings and/or industry commitments could have a material impact on our operations.

While we cannot predict the outcome of legislative or regulatory initiatives, such legislative and regulatory changes could have a material effect on our operations, particularly through more stringent and comprehensive safety regulations (such as integrity management requirements) to pipelines and gathering lines not previously subject to such requirements. While we expect any legislative or regulatory changes will provide sufficient time to come into compliance with the new requirements, the costs associated with compliance may have a material effect on our operations.

States are preempted by federal law from imposing pipeline safety standards below the minimum federal standards established by DOT, but they may establish more rigorous standards for intrastate gas and hazardous liquids pipelines. State agencies may also assume responsibility for enforcing intrastate pipeline regulations as a cooperating agency. In practice, states vary considerably in their authority and capacity to address pipeline safety. In the state of Oklahoma, the OCC’s Transportation Division, acting through the Pipeline Safety Department, administers the OCC’s intrastate regulatory program to assure the safe transportation of natural gas, petroleum and other hazardous materials by pipeline. The OCC develops regulations and other approaches to assure safety in design, construction, testing, operation, maintenance and emergency response to pipeline facilities. The OCC derives its authority over intrastate pipeline operations through state statutes and certification agreements with the DOT. A similar regime for safety regulation is in place in Texas and is administered by the Texas Railroad Commission. Our natural gas transmission and DOT regulated gathering pipelines have ongoing inspection and compliance programs designed to keep the facilities in compliance with pipeline safety and pollution control requirements.

We continue to incorporate new requirements into our procedures and budgets. We expect to incur increasing regulatory compliance costs, based on the intensification of the regulatory environment and forecasted changes to regulations as outlined above. In addition to regulatory changes, costs may be incurred when there is an accidental release of a commodity transported by our system, or a regulatory inspection identifies a deficiency in our required programs.

In addition to these pipeline safety requirements, we are subject to a number of federal and state laws and regulations, including the Occupational Safety and Health Act of 1970 (OSHA) and comparable state statutes, whose purpose is to protect the safety and health of workers, both generally and within the pipeline industry. In addition, the OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of the Federal Superfund Amendment and Reauthorization Act and comparable state statutes require that information be maintained concerning hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens. We are also subject to OSHA Process Safety Management regulations, which are designed to prevent or minimize the consequences of catastrophic releases of toxic, reactive, flammable or explosive chemicals. These regulations apply to any process which involves a chemical at or above the specified thresholds or any process which involves flammable liquid or gas, pressurized tanks, caverns and wells in excess of 10,000 pounds at various locations. We have an internal program of inspection designed to monitor and enforce compliance with worker safety and health requirements. Management believes that we are in material compliance with all applicable laws and regulations relating to worker safety and health.

The Department of Homeland Security Appropriation Act of 2007 requires the Department of Homeland Security, or DHS, to issue regulations establishing risk-based performance standards for the security of chemical and industrial facilities, including oil and gas facilities that are deemed to present “high levels of security risk.” The DHS issued an interim final rule in April 2007 regarding risk-based performance standards to be attained pursuant to this act and, on November 20, 2007, further issued an Appendix A to the interim rules that establish chemicals of interest and their respective threshold quantities that will trigger compliance with these interim rules. Covered facilities that are determined by DHS to pose a high level of security risk will be required to prepare and submit Security Vulnerability Assessments and Site Security Plans as well as comply with other regulatory requirements, including those regarding inspections, audits, recordkeeping, and protection of chemical-terrorism vulnerability information.

While we are not currently subject to governmental standards for the protection of computer-based systems and technology from cyber threats and attacks, proposals to establish such standards are being considered by the U.S. Congress and by U.S. Executive Branch departments and agencies, including the Department of Homeland Security, and we may become subject to such standards in the future. We have systems in place to monitor and address the risk of cyber-security breaches in our business, operations and control environments. We routinely review and update those systems as the nature of that risk requires. We are not aware of any cyber-security breach affecting any of our business, operations or control environments. A significant cyber-attack could have a material effect on our operations and those of our customers.

Environmental Regulation

General

Our activities are subject to stringent and complex federal, state and local laws and regulations governing environmental protection including the discharge of materials into the environment. These laws and regulations can restrict or impact our business activities in many ways, such as restricting the way we can handle or dispose of our wastes, requiring remedial action to mitigate pollution conditions that may be caused by our operations or that are attributable to former operations, regulating future construction activities to mitigate harm to threatened or endangered species, wetlands and migratory birds, and requiring the installation and operation of pollution control equipment. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial requirements and the issuance of orders enjoining future operations. Management believes that our operations are in material compliance with current federal, state and local environmental standards.

Environmental regulation can increase the cost of planning, design, initial installation, operation and maintenance of our facilities and has the potential to restrict or delay our operations and development projects, particularly pipeline projects. Historically, our total expenditures for environmental control measures and for remediation have not been significant in relation to our consolidated financial position or results of operations. Management believes, however, that it is reasonably likely that the trend in environmental legislation and regulations will continue towards more restrictive standards. Compliance with these standards is expected to increase the cost of conducting business.

Our routine environmental expenses for 2016 for technical support, fees, sampling, testing and other similar items were approximately $6 million. Reciprocating internal combustion engines maximum achievable control technology (RICE MACT) and greenhouse gases (GHG) expenses for 2016 were approximately $2 million. Routine expenses for 2017 to 2019 are expected to average $8 million per year, and RICE MACT and GHG costs are expected to average $2 million per year over the same timeframe. Costs for incidental environmental activities, such as permitting as part capital projects and waste disposal, are included in routine capital and operating expenses. Management continues to evaluate our compliance with existing and proposed environmental regulations and implements appropriate environmental programs in a competitive market.

Air

Our operations are subject to the federal Clean Air Act, as amended (CAA), and comparable state laws and regulations. These laws and regulations regulate emissions of air pollutants from various industrial sources, including natural gas processing plants and compressor stations, and also impose various monitoring and reporting requirements. Such laws and regulations may require that we obtain pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions or result in the increase of existing air emissions (including greenhouse gas emissions as discussed below), obtain and strictly comply with air permits containing various emissions and operational limitations or install emission control equipment. The EPA has also recently announced that it intends to develop methane emission standards for existing sources and has issued information collection requests to companies with production, gathering and boosting, gas processing, storage, and transmission facilities. We likely will be required to incur certain capital expenditures in the future for air pollution control equipment and technology in connection with obtaining and maintaining operating permits and approvals for air emissions. For more information, please read Item 1A, "Risk Factors–Costs of compliance with existing environmental laws and regulations are significant, and the cost of compliance with future environmental laws and regulations may adversely affect our financial position, results of operations and ability to make cash distributions to unitholders."

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Climate Change

More stringent laws and regulations relating to climate change and GHGs (including methane) may be adopted in the future and could cause us to incur material expenses in complying with them. The United States Congress has, from time to time, considered adopting legislation to reduce emissions of GHGs, and there has been a wide-ranging policy debate, both nationally and internationally, regarding the impact of these gases and possible means for their regulation. Some of the proposals would require industrial sources to meet stringent new standards that would require substantial reductions in GHG emissions. Please read Item 1A, "Risk Factors–Risks Related to Our Business–Our operations may incur substantial liabilities to comply with climate change legislation and regulatory initiatives." for more information. Following a finding by the U.S. Environmental Protection Agency (EPA) that certain GHGs represent an endangerment to human health, the EPA adopted two sets of rules regulating GHG emissions under the Clean Air Act. One requires a reduction in emissions of GHGs from motor vehicles beginning January 2, 2011. The other regulates emissions of GHGs from certain large stationary sources under the Clean Air Act's Prevention of Significant Deterioration and Title V programs, commencing when the motor vehicle standards took effect on January 2, 2011. Also, the EPA adopted its "Mandatory Reporting of Greenhouse Gases Rule" that requires the annual calculation and reporting of GHG emissions from natural gas transmission, gathering, processing and distribution systems and electric distribution systems that emit 25,000 metric tons or more of carbon dioxide equivalent (CO_{2e}) per year. These additional reporting requirements began in 2012 and we are currently in compliance. These permitting and reporting requirements could lead to further regulation of GHGs by the EPA.

Although the adoption of new legislation is uncertain, action by the EPA to impose new standards and reporting requirements regarding GHG emissions continues. For example, in May 2016, the EPA issued final new source performance standards imposing more stringent controls on methane and volatile organic compounds emissions at new and modified oil and natural gas production, processing, storage, and transmission facilities. The EPA has also announced that it intends to develop methane emission standards for existing sources and has issued information collection requests to companies with production, gathering and boosting, gas processing, storage, and transmission facilities. Similarly, in November 2016, the Bureau of Land Management finalized rules that require additional efforts by producers to reduce venting, flaring, and leaking of natural gas produced on federal and Native American lands. Furthermore, in October 2015, the EPA finalized proposed changes to its GHG reporting rule that requires additional reporting from natural gas transmission pipelines as well as gathering and boosting stations. This rule was effective January 1, 2016.

Several states have passed laws, adopted regulations or undertaken regulatory initiatives to reduce the emission of GHGs, primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. Oklahoma, Arkansas, Louisiana, Kansas, Missouri, Illinois, Tennessee, Mississippi, Alabama, North Dakota and Texas are not among them. Finally, in April 2016, the United States signed the Paris Agreement, which requires member countries to review and "represent a progression" in their nationally determined contributions, which set GHG emission reduction goals, every five years. If legislation or regulations are passed at the federal or state levels in the future requiring mandatory reductions of carbon dioxide, methane and other GHGs on our facilities, this could result in significant additional compliance costs that would affect the our future financial position, results of operations and cash flows.

The adoption of state or federal legislation or regulatory programs to reduce emissions of GHGs, including methane, could require us to incur increased operating costs, such as costs to purchase and operate emissions monitoring and control systems, to acquire emissions allowances or comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the natural gas we gather, treat and transport. Consequently, legislation and regulatory programs to reduce emissions of GHGs could have an adverse effect on our business, financial condition and results of operations. For more information, please read Item 1A, "Risk Factors–Our operations may incur substantial liabilities to comply with climate change legislation and regulatory initiatives."

National Environmental Policy Act (NEPA)

NEPA provides for regulatory review in connection with certain projects that involve federal lands or require certain actions by federal agencies, which implicates a number of other laws and regulations such as the Endangered Species Act (ESA), Migratory Bird Treaty Act, Rivers and Harbors Act, Clean Water Act, Bald and Golden Eagle Protection Act, Fish and Wildlife Coordination Act, Marine Mammal Protection Act and National Historic Preservation Act. The NEPA review process can be lengthy and subjective and can cause delays in projects. Some of our projects that require NEPA review are related to pipeline integrity. Ineffective implementation of this process could cause significant impacts to commercial and compliance projects.

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Protected Species

Certain federal laws, including the Bald and Golden Eagle Protection Act, the Migratory Bird Treaty Act and the Endangered Species Act, provide special protection to certain designated species. These laws and any state equivalents provide for significant civil and criminal penalties for unpermitted activities that result in harm to or harassment of certain protected animals and plants, including damage to their habitats. If such species are located in an area in which we conduct operations, or if additional species in those areas become subject to protection, our operations and development projects, particularly pipeline projects, could be restricted or delayed, or we could be required to implement expensive mitigation measures. Moreover, as a result of a settlement approved by the U.S. District Court for the District of Columbia in September 2011, the U.S. Fish and Wildlife Service is required to make a determination on listing of more than 250 species as endangered or threatened under the ESA by no later than completion of the agency’s 2017 fiscal year. The designation of previously unprotected species as threatened or endangered in areas where underlying property operations are conducted could cause us to incur increased costs arising from species protection measures or could result in limitations on our customer’s exploration and production activities that could have an adverse impact on demand for our services. Portions of the basins we serve are designated as critical or suitable habitat for threatened and endangered species. If additional portions of the basins we serve were designated as critical or suitable habitat for threatened and endangered species, it could adversely impact the cost of operating our systems and of constructing new facilities. Management believes that we are in material compliance with all applicable laws providing special protection to designated species.

Hazardous Substances and Waste

Our operations are subject to federal and state environmental laws and regulations relating to the management and release of hazardous substances, solid and hazardous wastes, and petroleum hydrocarbons. For instance, our operations are subject to the Comprehensive Environmental Response, Compensation and Liability Act of 1980 (CERCLA or Superfund) and comparable state cleanup laws that impose liability, without regard to the legality of the original conduct, on certain classes of persons responsible for the release of hazardous substances into the environment. These persons include current and prior owners or operators of the site where the release occurred and companies that disposed or arranged for the disposal of the hazardous substances found at the site. Under CERCLA, these persons may be subject to joint and several strict liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. CERCLA also authorizes the EPA and, in some instances, third parties to act in response to threats to the public health or the environment and to seek to recover the costs they incur from the responsible classes of persons. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment. Because we utilize various products and generate wastes that are considered hazardous substances for purposes of CERCLA, we could be subject to liability for the costs of cleaning up and restoring sites where those substances have been released to the environment. At this time, it is not anticipated that any associated liability will cause a significant impact to us.

Our operations also generate solid and hazardous wastes that are subject to the federal Resource Conservation and Recovery Act of 1976 (RCRA) as well as comparable state laws. While RCRA regulates both solid and hazardous wastes, it imposes detailed requirements for the handling, storage, treatment and disposal of hazardous waste. RCRA currently exempts many natural gas gathering and field processing wastes from classification as hazardous waste. However, it is possible that these wastes, which could include wastes currently generated during our operations, will in the future be designated as “hazardous wastes” and therefore be subject to more rigorous and costly disposal requirements. Such changes to the law could have an impact on our capital expenditures and operating expenses. Further, these RCRA-exempt oil and gas exploration and production wastes may still be regulated under state law or RCRA’s less stringent solid waste requirements. The transportation of natural gas in pipelines may also generate some hazardous wastes that are subject to RCRA or a comparable state law regime.

Water

Our operations are subject to the federal Clean Water Act and analogous state laws and regulations. These laws and regulations impose detailed requirements and strict controls regarding the discharge of pollutants into state and federal waters. The discharge of pollutants, including discharges resulting from a spill or leak, is prohibited unless authorized by a permit or other agency approval. In addition, the federal Clean Water Act and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. These permits may require us to monitor and sample the storm water runoff from some of our facilities. The federal Clean Water Act and regulations implemented thereunder also prohibit discharges of dredged and fill material in wetlands and other waters of the United States unless authorized by an appropriately issued permit. Spill prevention, control and countermeasure requirements of federal laws require appropriate containment berms and similar structures to help prevent the contamination of regulated waters in the event of a hydrocarbon tank spill, rupture or leak. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with many of these requirements.

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The primary federal law related to oil spill liability is the Oil Pollution Act (the OPA) which amends and augments oil spill provisions of the Clean Water Act and imposes certain duties and liabilities on certain “responsible parties” related to the prevention of oil spills and damages resulting from such spills in or threatening United States waters or adjoining shorelines. A liable “responsible party” includes the owner or operator of a facility, vessel or pipeline that is a source of an oil discharge or that poses the substantial threat of discharge, or in the case of offshore facilities, the lessee or permittee of the area in which a discharging facility is located. OPA assigns joint and several liability, without regard to fault, to each liable party for oil removal costs and a variety of public and private damages. Although defenses exist to the liability imposed by OPA, they are limited. In the event of an oil discharge or substantial threat of discharge, we may be liable for costs and damages.

Hydraulic Fracturing

Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons from tight formations. The process involves the injection of water, sand and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production. The process is regulated by state agencies, typically the state’s oil and gas commission. A number of federal agencies, including the EPA and the U.S. Department of Energy, are analyzing, or have been requested to review, a variety of environmental issues associated with hydraulic fracturing. For instance, the EPA released the final results of its comprehensive research study on the potential adverse impacts that hydraulic fracturing may have on drinking water resources in December 2016. The EPA concluded that hydraulic fracturing activities can impact drinking water resources under some circumstances, including large volume spills and inadequate mechanical integrity of wells. In addition, some states have adopted, and other states are considering adopting, regulations that could impose more stringent disclosure and/or well construction requirements on hydraulic fracturing operations.

State and federal regulatory agencies also recently focused on a possible connection between the operation of injection wells used for oil and gas wastewater disposal and seismic activity. Similar concerns have been raised that hydraulic fracturing may also contribute to seismic activity. When caused by human activity, such events are called induced seismicity. In March 2016, the United States Geological Survey identified six states with the most significant hazards from induced seismicity: Oklahoma, Kansas, Texas, Colorado, New Mexico, and Arkansas. In light of these concerns, some state regulatory agencies have modified their regulations or issued orders to address induced seismicity. Certain environmental and other groups have also suggested that additional federal, state and local laws and regulations may be needed to more closely regulate the hydraulic fracturing process.

If new laws or regulations that significantly restrict hydraulic fracturing or waste disposal wells are adopted, such laws could lead to greater opposition to, and litigation concerning, related oil and gas producing activities and to operational delays or increased operating costs for our customers, which in turn could reduce the demand for our services. For more information, please read Item 1A, “Risk Factors –Increased regulation of hydraulic fracturing could result in reductions or delays in natural gas production by our customers, which could adversely affect our financial position, results of operations and ability to make cash distributions to unitholders.” For a further discussion regarding contingencies relating to environmental laws and regulations, see Note 15 to Notes to Consolidated Financial Statements.

Our Employees

As of December 31, 2016, we employ approximately 1,600 employees with an additional 158 individuals providing services to us as seconded employees of OGE Energy. Personnel remain seconded to the Partnership, subject to certain termination rights of the Partnership and OGE Energy, in order to continue their participation in OGE Energy’s defined benefit and retiree medical plans. Please read Item 13, “Certain Relationships and Related Party

Transactions—Employee Agreements” for a description of the agreements governing these relationships.

Item 1A. Risk Factors

You should carefully consider each of the following risks and all of the other information contained in this Annual Report on Form 10-K in evaluating us and our common units. Some of these risks relate principally to our business and the industry in which we operate, while others relate principally to tax matters, ownership of our common units, our preferred units and securities markets generally. If any of the following risks were actually to occur, our business, financial position or results of operations could be materially adversely affected. In that case, we might not be able to pay the minimum quarterly distribution on our common units, or the trading price of our common units could decline.

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Risks Related to Our Business

We may not have sufficient cash from operations following the establishment of cash reserves and payment of fees and expenses, including cost reimbursements to our general partner and its affiliates, to enable us to pay the minimum quarterly distribution to holders of our common and subordinated units.

We may not have sufficient available cash each quarter to enable us to pay the minimum quarterly distribution. The amount of cash we can distribute on our units principally depends upon the amount of cash we generate from our operations, which will fluctuate from quarter to quarter based on, among other things:

- the fees and gross margins we realize with respect to the volume of natural gas, NGLs and crude oil that we handle;
- the prices of, levels of production of, and demand for natural gas, NGLs and crude oil;
- the volume of natural gas, NGLs and crude oil we gather, compress, treat, dehydrate, process, fractionate, transport and store;
- the relationship among prices for natural gas, NGLs and crude oil;
- cash calls and settlements of hedging positions;
- margin requirements on open price risk management assets and liabilities;
- the level of competition from other midstream energy companies;
- adverse effects of governmental and environmental regulation;
- the level of our operation and maintenance expenses and general and administrative costs; and
- prevailing economic conditions.

In addition, the actual amount of cash we will have available for distribution will depend on other factors, including:

- the level and timing of capital expenditures we make;
- the cost of acquisitions;
- our debt service requirements and other liabilities;
- fluctuations in working capital needs;
- our ability to borrow funds and access capital markets;
- restrictions contained in our debt agreements;
- the amount of cash reserves established by our general partner;
- distributions paid on our Series A Preferred Units; and
- other business risks affecting our cash levels.

Our contracts are subject to renewal risks.

As contracts with our existing suppliers and customers expire, we may have to negotiate extensions or renewals of those contracts or enter into new contracts with other suppliers and customers. We may be unable to extend or renew existing contracts or enter into new contracts on favorable commercial terms, if at all. Depending on prevailing market conditions at the time of an extension or renewal, gathering and processing customers with fee based contracts may desire to enter into contracts under different fee arrangements. Approximately 87% of our gross margin was generated from fee-based contracts during the year ended December 31, 2016. Likewise, our transportation and storage customers may choose not to extend or renew expiring contracts based on the economics of the related areas of production. To the extent we are unable to renew or replace our expiring contracts on terms that are favorable to us, if at all, or successfully manage our overall contract mix over time, our financial position, results of operations and ability to make cash distributions to unitholders could be adversely affected.

We depend on a small number of customers for a significant portion of our gathering and processing services revenues and our transportation and storage services revenues. The loss of, or reduction in volumes from, these customers could result in a decline in sales of our gathering and processing or transportation and storage services and adversely affect our financial position, results of operations and ability to make cash distributions to our unitholders.

For the year ended December 31, 2016, 49% of our gathered natural gas volumes were attributable to the affiliates of Continental, Vine, GeoSouthern, XTO and Apache and 51% of our transportation and storage service revenues were attributable to affiliates of CenterPoint Energy, Spire, XTO, AEP, and OGE Energy. The loss of all or even a portion of the gathering and processing or transportation and storage services for any of these customers, the failure to extend or replace these contracts or the

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extension or replacement of these contracts on less favorable terms, as a result of competition or otherwise, could adversely affect our financial position, results of operations and ability to make cash distributions to unitholders.

Our businesses are dependent, in part, on the drilling and production decisions of others.

Our businesses are dependent on the drilling and production of natural gas and crude oil. We have no control over the level of drilling activity in our areas of operation, or the amount of natural gas, NGL and crude oil reserves associated with wells connected to our systems. In addition, as the rate at which production from wells currently connected to our system naturally declines over time, our gross margin associated with those wells will also decline. To maintain or increase throughput levels on our gathering and transportation systems and the asset utilization rates at our natural gas processing plants, our customers must continually obtain new natural gas, NGL and crude oil supplies. The primary factors affecting our ability to obtain new supplies of natural gas, NGLs and crude oil and attract new customers to our assets are the level of successful drilling activity near our systems, our ability to compete for volumes from successful new wells and our ability to expand our capacity as needed. If we are not able to obtain new supplies of natural gas, NGLs and crude oil to replace the natural decline in volumes from existing wells, throughput on our gathering, processing, transportation and storage facilities would decline, which could adversely affect our financial position, results of operations and ability to make cash distributions to unitholders. We have no control over producers or their drilling and production decisions, which are affected by, among other things:

- the availability and cost of capital;
- prevailing and projected commodity prices, including the prices of natural gas, NGLs and crude oil;
- demand for natural gas, NGLs and crude oil;
- levels of reserves;
- geological considerations;
- environmental or other governmental regulations, including the availability of drilling permits and the regulation of hydraulic fracturing; and
- the availability of drilling rigs and other costs of production and equipment.

Fluctuations in energy prices can also greatly affect the development of new natural gas, NGL and crude oil reserves. Drilling and production activity generally decreases as commodity prices decrease. In general terms, the prices of natural gas, NGLs, crude oil and other hydrocarbon products fluctuate in response to changes in supply and demand, market uncertainty and a variety of additional factors that are beyond our control. Because of these factors, even if new natural gas, NGL or crude oil reserves are known to exist in areas served by our assets, producers may choose not to develop those reserves. Declines in natural gas, NGL or crude oil prices can have a negative impact on exploration, development and production activity and, if sustained, could lead to decreases in such activity. In early 2016, natural gas and crude oil prices dropped to their lowest levels in over 10 years. Both natural gas and crude oil prices increased moderately in the second half of 2016. Sustained low natural gas, NGL or crude oil prices could also lead producers to shut in production from their existing wells. Sustained reductions in exploration or production activity in our areas of operation could lead to further reductions in the utilization of our systems, which could adversely affect our financial position, results of operations and ability to make cash distributions to unitholders.

In addition, it may be more difficult to maintain or increase the current volumes on our gathering systems and in our processing plants, as several of the formations in the unconventional resource plays in which we operate generally have higher initial production rates and steeper production decline curves than wells in more conventional basins. Should we determine that the economics of our gathering assets do not justify the capital expenditures needed to grow or maintain volumes associated therewith, we may reduce such capital expenditures, which could cause revenues associated with these assets to decline over time. In addition to capital expenditures to support growth, the steeper production decline curves associated with unconventional resource plays may require us to incur higher maintenance capital expenditures relative to throughput over time, which will reduce our distributable cash flow.

Because of these and other factors, even if new reserves are known to exist in areas served by our assets, producers may choose not to develop those reserves. Reductions in drilling activity would result in our inability to maintain the current levels of throughput on our systems and could adversely affect our financial position, results of operations and ability to make cash distributions to unitholders.

Our industry is highly competitive, and increased competitive pressure could adversely affect our financial position, results of operations and ability to make cash distributions to unitholders.

We compete with similar enterprises in our respective areas of operation. The principal elements of competition are rates, terms of service and flexibility and reliability of service. Our competitors include large energy companies that have greater financial resources and access to supplies of natural gas, NGLs and crude oil than us. Some of these competitors may expand or construct gathering, processing, transportation and storage systems that would create additional competition for the services we provide to our customers. Excess pipeline capacity in the regions served by our interstate pipelines could also increase competition and adversely impact our ability to renew or enter into new contracts with respect to our available capacity when existing contracts expire. In addition, our customers that are significant producers of natural gas or crude oil may develop their own gathering, processing, transportation and storage systems in lieu of using ours. Our ability to renew or replace existing contracts with our customers at rates sufficient to maintain current revenues and cash flows could be adversely affected by the activities of our competitors and customers. Further, natural gas utilized as a fuel competes with other forms of energy available to end-users, including electricity, coal and liquid fuels. Increased demand for such forms of energy at the expense of natural gas could lead to a reduction in demand for natural gas gathering, processing, transportation and storage services. All of these competitive pressures could adversely affect our financial position, results of operations and ability to make cash distributions to unitholders.

We derive a substantial portion of our gross margin from subsidiaries through which we hold a substantial portion of our assets.

We derive a substantial portion of our gross margin from, and hold a substantial portion of our assets through, our subsidiaries. As a result, we depend on distributions from our subsidiaries in order to meet our payment obligations. In general, these subsidiaries are separate and distinct legal entities and have no obligation to provide us with funds for our payment obligations, whether by dividends, distributions, loans or otherwise. In addition, provisions of applicable law, such as those limiting the legal sources of dividends, limit our subsidiaries' ability to make payments or other distributions to us, and our subsidiaries could agree to contractual restrictions on their ability to make distributions.

Our right to receive any assets of any subsidiary, and therefore the right of our creditors to participate in those assets, will be effectively subordinated to the claims of that subsidiary's creditors, including trade creditors. In addition, even if we were a creditor of any subsidiary, our rights as a creditor would be subordinated to any security interest in the assets of that subsidiary and any indebtedness of the subsidiary senior to that held by us.

The amount of cash we have available for distribution to our limited partners depends primarily on our cash flow rather than on our profitability, which may prevent us from making distributions, even during periods in which we record net income.

The amount of cash we have available for distribution depends primarily upon our cash flow rather than on profitability. Profitability is affected by non-cash items but cash flow is not. As a result, we may make cash distributions during periods when we record losses for financial accounting purposes and may not make cash distributions during periods when we record net earnings for financial accounting purposes.

We may not be able to recover the costs of our substantial planned investment in capital improvements and additions, and the actual cost of such improvements and additions may be significantly higher than we anticipate.

Our business plan calls for investment in capital improvements and additions. For the year ending December 31, 2017, we estimate that expansion capital could range from approximately $455 million to $575 million and our maintenance capital could range from approximately $95 million to $125 million. For example, in the second quarter of 2016 we delayed the completion of the Wildhorse plant, a cryogenic processing facility that we plan to connect to our super-header system in Garvin County, Oklahoma. We also plan to construct natural gas gathering and compression infrastructure to support producer activity.

The construction of additions or modifications to our existing systems, and the construction of new midstream assets, involves numerous regulatory, environmental, political and legal uncertainties, many of which are beyond our control and may require the expenditure of significant amounts of capital, which may exceed our estimates. These projects may not be completed at the planned cost, on schedule or at all. The construction of new pipeline, gathering, treating, processing, compression or other facilities is subject to construction cost overruns due to labor costs, costs of equipment and materials such as steel, labor shortages or weather or other delays, inflation or other factors, which could be material. In addition, the construction of these facilities is typically subject to the receipt of approvals and permits from various regulatory agencies. Those agencies may not approve the projects in a timely manner, if at all, or may impose restrictions or conditions on the projects that could potentially prevent a project from proceeding, lengthen its expected completion schedule and/or increase its anticipated cost. Moreover, our revenues and cash flows may not increase immediately upon the expenditure of funds on a particular project. For instance, if we expand an existing pipeline or construct a new pipeline, the construction may occur over an extended period of time, and we may not receive any material increases in revenues or cash flows until the project is completed. In addition, we may construct facilities to capture anticipated future growth in production in a region in which such growth does not materialize. As a result, the new facilities may not be able to achieve our expected investment return, which could adversely affect our financial position, results of operations and ability to make cash distributions to unitholders.

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In connection with our capital investments, we may estimate, or engage a third party to estimate, potential reserves in areas to be developed prior to constructing facilities in those areas. To the extent we rely on estimates of future production in deciding to construct additions to our systems, those estimates may prove to be inaccurate due to numerous uncertainties inherent in estimating future production. As a result, new facilities may not be able to attract sufficient throughput to achieve expected investment return, which could adversely affect our financial position, results of operations and ability to make cash distributions to unitholders. In addition, the construction of additions to existing gathering and transportation assets may require new rights-of-way prior to construction. Those rights-of-way to connect new natural gas supplies to existing gathering lines may be unavailable and we may not be able to capitalize on attractive expansion opportunities. Additionally, it may become more expensive to obtain new rights-of-way or to renew existing rights-of-way. If the cost of renewing or obtaining new rights-of-way increases, our financial position, results of operations and ability to make cash distributions to unitholders could be adversely affected.

Natural gas, NGL and crude oil prices are volatile, and changes in these prices could adversely affect our financial position, results of operations and our ability to make cash distributions to unitholders.

Our financial position, results of operations and ability to make cash distributions to unitholders could be negatively affected by adverse movements in the prices of natural gas, NGLs and crude oil depending on factors that are beyond our control. These factors include demand for these commodities, which fluctuates with changes in market and economic conditions and other factors, including the impact of seasonality and weather, general economic conditions, the level of domestic and offshore natural gas production and consumption, the availability of imported natural gas, LNG, NGLs and crude oil, actions taken by foreign natural gas and oil producing nations, the availability of local, intrastate and interstate transportation systems, the availability and marketing of competitive fuels, the impact of energy conservation efforts, technological advances affecting energy consumption and the extent of governmental regulation and taxation. In early 2016, natural gas and crude oil prices dropped to their lowest levels in over 10 years. Both natural gas and crude oil prices increased moderately in the second half of 2016.

Our natural gas processing arrangements expose us to commodity price fluctuations. In 2016, 8%, 46%, and 46% of our processing plant inlet volumes consisted of keep-whole arrangements, percent-of-proceeds or percent-of-liquids, and fee-based, respectively. Under a typical keep-whole arrangement, we process raw natural gas, extract the NGLs, replace the extracted NGLs with a Btu equivalent amount of natural gas, deliver the processed and replacement natural gas to the producer, retain the NGLs, and sell the NGLs for our own account. If we are unable to sell the NGLs extracted for more than the cost of the replacement natural gas, the margins on our sale of goods will be negatively affected.

Under a typical percent-of-proceeds processing arrangement, we purchase raw natural gas at a cost that is based on the amount of natural gas and NGLs contained in the raw natural gas. We then process the raw natural gas, extract the NGLs, and sell the processed natural gas and NGLs for our own account. If we are unable to sell the processed natural gas and NGLs for more than the cost of the raw natural gas, the margins on our sale of goods will be negatively affected.

Under a typical percent-of-liquids processing arrangement and a typical fee-based arrangement, we purchase a portion of the raw natural gas that is equivalent to the amount of NGLs it contains, process the raw natural gas, extract the NGLs, return the processed natural gas to the producer, and sell the NGLs for our own account. If we are unable to sell the processed natural gas and NGLs for more than the cost of raw natural gas, the margins on our sale of goods will be negatively affected.

At any given time, our overall portfolio of processing contracts may reflect a net short position in natural gas (meaning that we are a net buyer of natural gas) and a net long position in NGLs (meaning that we are a net seller of NGLs). As a result, our gross margin could be adversely impacted to the extent the price of NGLs decreases in relation to the price of natural gas.

We are exposed to credit risks of our customers, and any material nonpayment or nonperformance by our key customers could adversely affect our financial position, results of operations and ability to make cash distributions to unitholders.

Some of our customers may experience financial problems that could have a significant effect on their creditworthiness. Severe financial problems encountered by our customers could limit our ability to collect amounts owed to us, or to enforce performance of obligations under contractual arrangements. In addition, many of our customers finance their activities through cash flow from operations, the incurrence of debt or the issuance of equity. The combination of reduction of cash flow resulting from declines in commodity prices, a reduction in borrowing bases under reserve-based credit facility and the lack of availability of debt or equity financing may result in a significant reduction of our customers' liquidity and limit their ability to make payment or perform on their obligations to us. Furthermore, some of our customers may be highly leveraged and subject to their own operating and regulatory risks, which increases the risk that they may default on their obligations to us. Financial problems experienced by our customers could result in the impairment of our assets, reduction of our operating cash flows and may also reduce or curtail their future use of our products and services, which could reduce our revenues.

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

We have been authorized by the Federal Energy Regulatory Commission, or FERC, to provide transportation and storage services at our facilities at negotiated rates. Generally, negotiated rates are in excess of the maximum recourse rates allowed by FERC, but it is possible that costs to perform services under “negotiated rate” contracts will exceed the revenues obtained under these agreements. If this occurs, it could decrease the cash flow realized by our systems and, therefore, decrease the cash we have available for distribution to our unitholders.

As of December 31, 2016, approximately 54% of our contracted firm transportation capacity and 44% of our contracted firm storage capacity was subscribed under such “negotiated rate” contracts. These contracts generally do not include provisions allowing for adjustment for increased costs due to inflation, pipeline safety activities or other factors that are not tied to an applicable tracking mechanism authorized by FERC. Successful recovery of any shortfall of revenue, representing the difference between “recourse rates” (if higher) and negotiated rates, is not assured under current FERC policies.

If third-party pipelines and other facilities interconnected to our gathering, processing or transportation facilities become partially or fully unavailable to us for any reason, our financial position, results of operations and ability to make cash distributions to unitholders could be adversely affected.

We depend upon third-party pipelines to deliver natural gas to, and take natural gas from, our natural gas transportation systems and upon third party pipelines to take crude oil from our crude oil gathering systems. We also depend on third-party facilities to transport and fractionate NGLs that are delivered to the third party at the tailgates of our processing plants. Fractionation is the separation of the heterogeneous mixture of extracted NGLs into individual components for end-use sale. For example, an outage or disruption on certain pipelines or fractionators operated by a third party could result in the shutdown of certain of our processing plants and gathering systems, and a prolonged outage or disruption could ultimately result in a reduction in the volume of natural gas we gather and NGLs we are able to produce. Additionally, we depend on third parties to provide electricity for compression at many of our facilities. Since we do not own or operate any of these third-party pipelines or other facilities, their continuing operation is not within our control. If any of these third-party pipelines or other facilities become partially or fully unavailable to us for any reason, our financial position, results of operations and ability to make cash distributions to unitholders could be adversely affected.

We do not own all of the land on which our pipelines and facilities are located, which could disrupt 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 may obtain the rights to construct and operate our pipelines on land owned by third parties and governmental agencies for a specific period of time. A loss of these rights, through our inability to renew right-of-way contracts or otherwise, could cause us to cease operations temporarily or permanently on the affected land, increase costs related to the construction and continuing operations elsewhere, and adversely affect our financial position, results of operations and ability to make cash distributions to unitholders.

We conduct a portion of our operations through joint ventures, which subject us to additional risks that could adversely affect the success of these operations and our financial position, results of operations and ability to make cash distributions to unitholders.

We conduct a portion of our operations through joint ventures with third parties, including Spectra Energy Partners, LP, DCP Midstream Partners, LP, Trans Louisiana Gas Pipeline, Inc. and Pablo Gathering LLC. We may also enter into other joint venture arrangements in the future. These third parties may have obligations that are important to the success of the joint venture, such as the obligation to pay their share of capital and other costs of the joint venture. The performance of these third-party obligations, including the ability of the third parties to satisfy their obligations under these arrangements, is outside our control. If these parties do not satisfy their obligations under these arrangements, our business may be adversely affected.

Our joint venture arrangements may involve risks not otherwise present when operating assets directly, including, for example:

- our joint venture partners may share certain approval rights over major decisions;

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- our joint venture partners may not pay their share of the joint venture's obligations, leaving us liable for their shares of joint venture liabilities;
- we may be unable to control the amount of cash we will receive from the joint venture;
- we may incur liabilities as a result of an action taken by our joint venture partners;
- we may be required to devote significant management time to the requirements of and matters relating to the joint ventures;
- our insurance policies may not fully cover loss or damage incurred by both us and our joint venture partners in certain circumstances;
- our joint venture partners may be in a position to take actions contrary to our instructions or requests or contrary to our policies or objectives; and
- disputes between us and our joint venture partners may result in delays, litigation or operational impasses.

The risks described above or the failure to continue our joint ventures or to resolve disagreements with our joint venture partners could adversely affect our ability to transact the business that is the subject of such joint venture, which would in turn adversely affect our financial position, results of operations and ability to make cash distributions to unitholders. The agreements under which we formed certain joint ventures may subject us to various risks, limit the actions we may take with respect to the assets subject to the joint venture and require us to grant rights to our joint venture partners that could limit our ability to benefit fully from future positive developments. Some joint ventures require us to make significant capital expenditures. If we do not timely meet our financial commitments or otherwise do not comply with our joint venture agreements, our rights to participate, exercise operator rights or otherwise influence or benefit from the joint venture may be adversely affected. Certain of our joint venture partners may have substantially greater financial resources than we have and we may not be able to secure the funding necessary to participate in operations our joint venture partners propose, thereby reducing our ability to benefit from the joint venture.

Under certain circumstances, Spectra Energy Partners, LP could have the right to purchase an ownership interest in SESH at fair market value.

We own a 50% ownership interest in SESH. The remaining 50% ownership interests are held by Spectra Energy Partners, LP. CenterPoint Energy owns 54.1% of our common and subordinated units, 100% of our Series A Preferred Units and a 40% economic interest in our general partner. Pursuant to the terms of the limited liability company agreement of SESH, as amended (the SESH LLC Agreement), if, at any time, CenterPoint Energy has a right to receive less than 50% of our distributions through its interests in us and in our general partner, or does not have the ability to exercise certain control rights, Spectra Energy Partners, LP could have the right to purchase our interest in SESH at fair market value, subject to certain exceptions.

An impairment of long-lived assets, including intangible assets, equity method investments or goodwill could reduce our earnings.

Long-lived assets, including intangible assets with finite useful lives and property, plant and equipment, are evaluated for impairment when events or changes in circumstances indicate that the carrying amount may not be recoverable. An impairment of long-lived assets is recognized if the carrying amount is not recoverable and exceeds fair value. For example, we recorded aggregate impairments for our Service Star business line of $38 million during the years ended December 31, 2016, 2015, 2014 and 2013, a $25 million impairment of our Atoka assets in our gathering and processing segment during the year ended December 31, 2015, and a $12 million impairment of jurisdictional pipelines in our transportation and storage segment during the year ended December 31, 2015.

Equity method investments are evaluated for impairment when events or circumstances indicate that the carrying value of the investment might not be recoverable. An impairment of an equity method investment is recognized if the fair value of the investment as a whole, and not the underlying assets, has declined and the decline is other than temporary. An example of an investment that we account for under the equity method is our investment in SESH. If we enter into additional joint ventures, we could have additional equity method investments.

Goodwill is evaluated for impairment on an annual basis as well as when events or circumstances change that would more likely than not reduce the fair value of a reporting unit is below its carrying amount. An impairment of goodwill is recognized if the carrying value of a reporting unit exceeds its fair value and the carrying amount of that reporting unit's good will exceeds the implied value of that goodwill. For example, we recorded impairments to goodwill of $1,087 million during the year ended December 31, 2015. Although as a result of these impairments we had no goodwill recorded as of December 31, 2016 or 2015, we could record goodwill as a result of future acquisitions.

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We could experience future events or circumstances that result in an impairment of long-lived assets, including intangible assets, equity method investments, or goodwill. If we recognize an impairment, we would take an immediate non-cash charge to earnings with a correlative effect on equity and balance sheet leverage as measured by debt to total capitalization. As a result, an impairment could have an adverse effect on our results of operations and our ability to satisfy the financial ratios or other covenants under our existing or future debt agreements.

Our business involves many hazards and operational risks, some of which may not be fully covered by insurance. Insufficient insurance coverage and increased insurance costs could adversely affect our financial position, results of operations and our ability to make cash distributions to unitholders.

Our operations are subject to all of the risks and hazards inherent in the gathering, processing, transportation and storage of natural gas and crude oil, including:

- damage to pipelines and plants, related equipment and surrounding properties caused by hurricanes, tornadoes, floods, fires and other natural disasters, acts of terrorism and actions by third parties;
- inadvertent damage from construction, vehicles, farm and utility equipment;
- leaks of natural gas, NGLs, crude oil and other hydrocarbons or losses of natural gas, NGLs and crude oil as a result of the malfunction of equipment or facilities;
- ruptures, fires and explosions; and
- other hazards that could also result in personal injury and loss of life, pollution and suspension of operations.

These risks could result in substantial losses due to personal injury or loss of life, severe damage to and destruction of property, plant and equipment and pollution or other environmental damage. These risks may also result in curtailment or suspension of our operations. A natural disaster or other hazard affecting the areas in which we operate could adversely affect our results of operations. We are not fully insured against all risks inherent in our business. We currently have general liability and property insurance in place to cover certain of our facilities in amounts that we consider appropriate. Such policies are subject to certain limits and deductibles. We have business interruption insurance coverage for some but not all of our operations. Insurance coverage may not be available in the future at current costs or on commercially reasonable terms, and the insurance proceeds received for any loss of, or any damage to, any of our facilities may not be sufficient to restore the loss or damage without adversely affecting our financial position, results of operations and our ability to make cash distributions to unitholders.

The use of derivative contracts by us and our subsidiaries in the normal course of business could result in financial losses that could adversely affect our financial position, results of operations and our ability to make cash distributions to unitholders.

We and our subsidiaries periodically use derivative instruments, such as swaps, options, futures and forwards, to manage our commodity and financial market risks. We and our subsidiaries could recognize financial losses as a result of volatility in the market values of these contracts, or should a counterparty fail to perform. In the absence of actively quoted market prices and pricing information from external sources, the valuation of these financial instruments can involve management’s judgment or use of estimates. As a result, changes in the underlying assumptions or use of alternative valuation methods could affect the reported fair value of these contracts.

Failure to attract and retain an appropriately qualified workforce could adversely impact our results of operations.

Our business is dependent on our ability to recruit, retain and motivate employees. Certain circumstances, such as an aging workforce without appropriate replacements, a mismatch of existing skill sets to future needs, competition for skilled labor or the unavailability of contract resources may lead to operating challenges such as a lack of resources, loss of knowledge or a lengthy time period associated with skill development. Our costs, including costs for contractors to replace employees, productivity costs and safety costs, may rise. Failure to hire and adequately train replacement employees, including the transfer of significant internal historical knowledge and expertise to the new employees, or the future availability and cost of contract labor may adversely affect our ability to manage and operate our business. If we are unable to successfully attract and retain an appropriately qualified workforce, our results of operations could be negatively affected.

We transitioned seconded employees from CenterPoint Energy and OGE Energy to the Partnership effective January 1, 2015, except for those employees who are participants under OGE Energy’s defined benefit and retiree medical plans, who will remain seconded to the Partnership, subject to certain termination rights of the Partnership and OGE Energy. Employees of OGE Energy that we determine to hire are under no obligation to accept our offer of employment on the terms we provide, or at all.

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Our ability to grow is dependent on our ability to access external financing sources.

Our operating subsidiaries distribute all of their available cash to us, and we distribute all of our available cash to our unitholders. As a result, we and our operating subsidiaries rely primarily upon external financing sources, including commercial bank borrowings and the issuance of debt and equity securities, to fund acquisitions and expansion capital expenditures. As a result, to the extent we or our operating subsidiaries are unable to finance growth externally, our and our operating subsidiaries' cash distribution policy will significantly impair our and our operating subsidiaries' ability to grow. In addition, because we and our operating subsidiaries distribute all available cash, our and our operating subsidiaries' growth may not be as fast as businesses that reinvest their available cash to expand ongoing operations.

To the extent we issue additional units in connection with any acquisitions or expansion capital expenditures, the payment of distributions on those additional units may increase the risk that we will be unable to maintain or increase our per unit distribution level, which in turn may impact the available cash that we have to distribute on each unit. There are no limitations in our partnership agreement on our ability to issue additional units, including units ranking senior to the common units. The incurrence of additional commercial borrowings or other debt by us or our operating subsidiaries to finance our growth strategy would result in increased interest expense, which in turn may negatively impact the available cash that our operating subsidiaries have to distribute to us, and that we have to distribute to our unitholders.

We depend on access to the capital markets to fund our expansion capital expenditures. Historically, unit prices of midstream master limited partnerships have experienced periods of volatility. In addition, because our common units are yield-based securities, rising market interest rates could impact the relative attractiveness of our common units to investors. As a result of capital market volatility, we may be unable to issue equity or debt on satisfactory terms, or at all, which may limit our ability to expand our operations or make future acquisitions.

Our merger and acquisition activities may not be successful or may result in completed acquisitions that do not perform as anticipated, which could adversely affect our financial position, results of operations or future growth.

From time to time, we have made, and we intend to continue to make, acquisitions of businesses and assets. Such acquisitions involve substantial risks, including the following:

- acquired businesses or assets may not produce revenues, earnings or cash flow at anticipated levels;
- acquired businesses or assets could have environmental, permitting or other problems for which contractual protections prove inadequate;
- we may assume liabilities that were not disclosed to us, that exceed our estimates, or for which our rights to indemnification from the seller are limited;
- we may be unable to integrate acquired businesses successfully and realize anticipated economic, operational and other benefits in a timely manner, which could result in substantial costs and delays or other operational, technical or financial problems; and
- acquisitions, or the pursuit of acquisitions, could disrupt our ongoing businesses, distract management, divert resources and make it difficult to maintain our current business standards, controls and procedures.

In addition, our growth strategy includes, in part, the ability to make acquisitions on economically acceptable terms. If we are unable to make acquisitions or if our acquisitions do not perform as anticipated, our future growth may be adversely affected.

Our and our operating subsidiaries' debt levels may limit our and their flexibility in obtaining additional financing and in pursuing other business opportunities.

As of December 31, 2016, we had approximately $3 billion of long-term debt outstanding, excluding the premiums on senior notes. We have a $1.75 billion Revolving Credit Facility for working capital, capital expenditures and other partnership purposes, including acquisitions, of which $1.1 billion was available as of February 1, 2017. We have the ability to incur additional debt, subject to limitations in our credit facilities. The levels of our debt could have important consequences, including the following:

- the ability to obtain additional financing, if necessary, for working capital, capital expenditures, acquisitions or other purposes may be impaired or the financing may not be available on favorable terms, if at all;
- a portion of cash flows will be required to make interest payments on the debt, reducing the funds that would otherwise be available for operations, future business opportunities and distributions;
- our debt level will make us more vulnerable to competitive pressures or a downturn in our business or the economy generally; and

- our debt level may limit our flexibility in responding to changing business and economic conditions.

Our and our operating subsidiaries' ability to service our and their debt will depend upon, among other things, their future financial and operating performance, which will be affected by prevailing economic conditions, commodity prices and financial, business, regulatory and other factors, some of which are beyond our and their control. If operating results are not sufficient to service our or our operating subsidiaries' current or future indebtedness, we and they may be forced to take actions such as reducing distributions, reducing or delaying business activities, acquisitions, investments or capital expenditures, selling assets, restructuring or refinancing debt, or seeking additional equity capital. These actions may not be effected on satisfactory terms, or at all. Please see Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources."

Our credit facilities contain operating and financial restrictions, including covenants and restrictions that may be affected by events beyond our control, which could adversely affect our financial condition, results of operations and ability to make cash distributions to our unitholders.

Our credit facilities contain customary covenants that, among other things, limit our ability to:

- permit our subsidiaries to incur or guarantee additional debt;
- incur or permit to exist certain liens on assets;
- dispose of assets;
- merge or consolidate with another company or engage in a change of control;
- enter into transactions with affiliates on non-arm's length terms; and
- change the nature of our business.

Our credit facilities also require us to maintain certain financial ratios. Our ability to meet those financial ratios can be affected by events beyond our control, and we cannot assure you that we will meet those ratios. In addition, our credit facilities contain events of default customary for agreements of this nature.

Our ability to comply with the covenants and restrictions contained in our credit facilities 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 facilities, a significant portion of our indebtedness may become immediately due and payable. In addition, our lenders' commitments to make further loans to us under the Revolving Credit Facility may be suspended or terminated. We might not have, or be able to obtain, sufficient funds to make these accelerated payments. Please see Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources."

Affiliates of our general partner, including CenterPoint Energy and OGE Energy, may compete with us, and neither our general partner nor its affiliates have any obligation to present business opportunities to us.

Under our omnibus agreement, CenterPoint Energy, OGE Energy and their affiliates have agreed to hold or otherwise conduct all of their respective midstream operations located within the United States through us. This requirement will cease to apply to both CenterPoint Energy and OGE Energy as soon as either CenterPoint Energy or OGE Energy ceases to hold any interest in our general partner or at least 20% of our common units. In addition, if CenterPoint Energy or OGE Energy acquires any assets or equity of any person engaged in midstream operations with a value in excess of $50 million (or $100 million in the aggregate with such party's other acquired midstream operations that have not been offered to us), the acquiring party will be required to offer to us such assets or equity for such value. If we do not purchase such assets, the acquiring party will be free to retain and operate such midstream assets, so long as the value of the assets does not reach certain thresholds.

As a result, under the circumstances described above, CenterPoint Energy and OGE Energy have the ability to construct or acquire assets that directly compete with our assets. Pursuant to the terms of our partnership agreement, the doctrine of corporate opportunity, or any analogous doctrine, does not apply to our general partner or any of its affiliates, including its executive officers and directors and CenterPoint Energy and OGE Energy. Any such person or entity that becomes aware of a potential transaction, agreement, arrangement or other matter that may be an opportunity for us will not have any duty to communicate or offer such opportunity to us. Any such person or entity will not be liable to us or to any limited partner for breach of any fiduciary duty or other duty by reason of the fact that such person or entity pursues or acquires such opportunity for itself, directs such opportunity to another person or entity or does not communicate such opportunity or information to us. This may create actual and potential conflicts of interest between us and affiliates of our general partner and result in less than favorable treatment of us and our common unitholders.

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If we fail to maintain an effective system of internal controls, then we may not be able to accurately report our financial results or prevent fraud. As a result, current and potential unitholders could lose confidence in our financial reporting, which would harm our business and the trading price of our common units.

Effective internal controls are necessary for us to provide reliable financial reports, prevent fraud and operate successfully as a public company. If our efforts to maintain internal controls are not successful, we are unable to maintain adequate controls over our financial processes and reporting in the future or we are unable to comply with our obligations under Section 404 of the Sarbanes-Oxley Act of 2002, our operating results could be harmed or we may fail to meet our reporting obligations. Ineffective internal controls also could cause investors to lose confidence in our reported financial information, which would likely have a negative effect on the trading price of our common units.

Cyber-attacks, acts of terrorism or other disruptions could adversely impact our financial position, results of operations and ability to make cash distributions to unitholders.

We are subject to cyber-security risks related to breaches in the systems and technology that we use (i) to manage our operations and other business processes and (ii) to protect sensitive information maintained in the normal course of our businesses. The gathering, processing and transportation of natural gas from our gathering, processing and pipeline facilities and crude oil gathering pipeline systems are dependent on communications among our facilities and with third-party systems that may be delivering natural gas or crude oil into or receiving natural gas or crude oil and other products from our facilities. Disruption of those communications, whether caused by physical disruption such as storms or other natural phenomena, by failure of equipment or technology, or by manmade events, such as cyber-attacks or acts of terrorism, may disrupt our ability to deliver natural gas and control these assets. Cyber-attacks could also result in the loss of confidential or proprietary data or security breaches of other information technology systems that could disrupt our operations and critical business functions, adversely affect our reputation, and subject us to possible legal claims and liability. We are not fully insured against all cyber-security risks. In addition, our natural gas pipeline systems may be targets of terrorist activities that could disrupt our ability to conduct our business. It is possible that any of these occurrences, or a combination of them, could adversely affect our financial position, results of operations, and ability to make cash distributions to unitholders.

We may be unable to obtain or renew permits necessary for our operations, which could inhibit our ability to do business.

Performance of our operations require that we obtain and maintain a number of federal and state permits, licenses and approvals with terms and conditions containing a significant number of prescriptive limits and performance standards in order to operate. All of these permits, licenses, approval limits and standards require a significant amount of monitoring, record keeping and reporting in order to demonstrate compliance with the underlying permit, license, approval limit or standard. Noncompliance or incomplete documentation of our compliance status may result in the imposition of fines, penalties and injunctive relief. A decision by a government agency to deny or delay the issuance of a new or existing material permit or other approval, or to revoke or substantially modify an existing permit or other approval, could adversely affect our ability to initiate or continue operations at the affected location or facility and on our financial condition, results of operations and ability to make cash distributions to unitholders.

Additionally, in order to obtain permits and renewals of permits and other approvals in the future, we may be required to prepare and present data to governmental authorities pertaining to the potential adverse impact that any proposed pipeline or processing-related activities may have on the environment, individually or in the aggregate, including on public and Indian lands. Certain approval procedures may require preparation of archaeological surveys, endangered species studies and other studies to assess the environmental impact of new sites or the expansion of existing sites. Compliance with these regulatory requirements is expensive and significantly lengthens the time required to prepare applications and to receive authorizations.

Costs of compliance with existing environmental laws and regulations are significant, and the cost of compliance with future environmental laws and regulations may adversely affect our financial position, results of operations and ability to make cash distributions to unitholders.

We are subject to extensive federal, state and local environmental statutes, rules and regulations relating to air quality, water quality, waste management, wildlife conservation, natural resources and health and safety that could, among other things, delay or increase our costs of construction, restrict or limit the output of certain facilities and/or require additional pollution control equipment and otherwise increase costs. For instance, in May 2016, the EPA issued final NSPS governing methane emissions imposing more stringent controls on methane and volatile organic compounds emissions at new and modified oil and natural gas production, processing, storage, and transmission facilities. These rules have required changes to our operations, including the installation of new equipment to control emissions. The EPA has also announced that it intends to impose methane emission standards for existing sources and has issued information collection requests to companies with production, gathering and boosting,

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gas processing, storage, and transmission facilities. Additionally, several states are pursuing similar measures to regulate emissions of methane from new and existing sources. There are significant capital, operating and other costs associated with compliance with these environmental statutes, rules and regulations. As a result of this continued regulatory focus, future federal and state regulations relating to our gathering and processing, transmission, and storage operations remain a possibility and could result in increased compliance costs on our operations. Furthermore, if new or more stringent federal, state or local legal restrictions are adopted in areas where our oil and natural gas exploration and production customers operate, they could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling wells, some or all of which could adversely affect demand for our services to those customers.

There is inherent risk of the incurrence of environmental costs and liabilities in our operations due to our handling of natural gas, NGLs, crude oil, and produced water, as well as air emissions related to our operations and historical industry operations and waste disposal practices. These matters are subject to stringent and complex federal, state and local laws and regulations governing environmental protection, including the discharge of materials into the environment and the protection of plants, wildlife, and natural and cultural resources. These laws and regulations can restrict or impact our business activities in many ways, such as restricting the way we can handle or dispose of wastes or requiring remedial action to mitigate pollution conditions that may be caused by our operations or that are attributable to former operators. Joint and several strict liability may be incurred, without regard to fault, under certain of these environmental laws and regulations in connection with discharges or releases of wastes on, under or from our properties and facilities, many of which have been used for midstream activities for a number of years, oftentimes by third parties not under our control. Private parties, including the owners of the properties through which our gathering systems pass and facilities where our wastes are taken for reclamation or disposal, may also have the right to pursue legal actions to enforce compliance, as well as to seek damages for non-compliance, with environmental laws and regulations or for personal injury or property damage. For example, an accidental release from one of our pipelines could subject us to substantial liabilities arising from environmental cleanup and restoration costs, claims made by neighboring landowners and other third parties for personal injury and property damage and fines or penalties for related violations of environmental laws or regulations. We may be unable to recover these costs from insurance. Moreover, the possibility exists that stricter laws, regulations or enforcement policies could significantly increase compliance costs and the cost of any remediation that may become necessary. Further, stricter requirements could negatively impact our customers' production and operations, resulting in less demand for our services.

Increased regulation of hydraulic fracturing could result in reductions or delays in natural gas production by our customers, which could adversely affect our financial position, results of operations and ability to make cash distributions to unitholders.

Hydraulic fracturing is common practice that is used by many of our customers to stimulate production of natural gas and crude oil from dense subsurface rock formations. The hydraulic fracturing process involves the injection of water, sand, and chemicals under pressure into targeted subsurface formations to fracture the surrounding rock and stimulate production. Hydraulic fracturing typically is regulated by state oil and natural gas commissions. In addition, certain federal agencies have proposed additional laws and regulations to more closely regulate the hydraulic fracturing process. For example, in May 2016, the EPA issued final new source performance standard requirements that impose more stringent controls on methane and volatile organic compounds emissions from oil and gas development and production operations, including hydraulic fracturing and other well completion activity. The EPA also released the final results of its comprehensive research study on the potential adverse impacts that hydraulic fracturing may have on drinking water resources in December 2016. The EPA concluded that hydraulic fracturing activities can impact drinking water resources under some circumstances, including large volume spills and inadequate mechanical integrity of wells. The results of EPA's study could spur action towards federal legislation and regulation of hydraulic fracturing or similar production operations. In past sessions, Congress has considered, but not passed, legislation to provide for federal regulation of hydraulic fracturing under the Safe Drinking Water Act (SDWA) and to require disclosure of the chemicals used in the hydraulic fracturing process. The EPA has issued SDWA permitting guidance for hydraulic fracturing operations involving the use of diesel fuel in fracturing fluids in those states where the EPA is the permitting authority. Additionally, the Bureau of Land Management issued final rules to regulate hydraulic fracturing on federal lands in March 2015. Although these rules were struck down by a federal court in Wyoming in June 2016, an appeal of the decision is still pending.

Some states have adopted, and other states are considering adopting, legal requirements that could impose more stringent permitting, public disclosure or well construction requirements on hydraulic fracturing activities. Local government also may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular, in some cases banning hydraulic fracturing entirely. If new or more stringent federal, state or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where our oil and natural gas exploration and production customers operate, they could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling wells, some or all of which activities could adversely affect demand for our services to those customers.

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State and federal regulatory agencies recently have focused on a possible connection between the operation of injection wells used for oil and gas waste disposal and seismic activity. Similar concerns have been raised that hydraulic fracturing may also contribute to seismic activity. When caused by human activity, such events are called induced seismicity. In March 2016, the United States Geological Survey identified six states with the most significant hazards from induced seismicity, including Oklahoma, Kansas, Texas, Colorado, New Mexico, and Arkansas. In light of these concerns, some state regulatory agencies have modified their regulations or issued orders to address induced seismicity. For example, the Oklahoma Corporation Commission (OCC) has implemented volume reduction plans, and at times required shut-ins, for disposal wells injecting wastewater from oil and gas operations into the Arbuckle formation. The OCC also recently released well completion seismicity guidelines for operators in the SCOOP and STACK that call for hydraulic fracturing operations to be suspended following earthquakes of certain magnitudes in the vicinity. Certain environmental and other groups have also suggested that additional federal, state and local laws and regulations may be needed to more closely regulate the hydraulic fracturing process. We cannot predict whether additional federal, state or local laws or regulations applicable to hydraulic fracturing will be enacted in the future and, if so, what actions any such laws or regulations would require or prohibit. Increased regulation and attention given to induced seismicity could lead to greater opposition to, and litigation concerning, oil and gas activities utilizing hydraulic fracturing or injection wells for waste disposal. Additional legislation or regulation could also lead to operational delays or increased operating costs for our customers, which in turn could reduce the demand for our services.

Other governmental agencies, including the U.S. Department of Energy, have evaluated or are evaluating various other aspects of hydraulic fracturing. These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the SDWA or other regulatory mechanisms.

Our operations may incur substantial liabilities to comply with climate change legislation and regulatory initiatives.

Because our operations emit various types of greenhouse gases, legislation and regulations governing greenhouse gas emissions could increase our costs related to operating and maintaining our facilities, and could delay future permitting. At the federal level, the EPA has adopted regulations under existing provisions of the federal Clean Air Act that, among other things, require the monitoring and reporting of GHG emissions from specified onshore and offshore oil and natural gas production sources in the United States on an annual basis, which include certain of our operations. Additional rules, such as the updates to the oil and gas new source performance standard requirements finalized by the EPA in May 2016 could affect our ability to obtain air permits for new or modified facilities or require our operations to incur additional expenses to control air emissions by installing emissions control technologies and adhering to a variety of work practice and other requirements. These requirements could increase the costs of development and production, reducing the profits available to us and potentially impairing our operator’s ability to economically develop our properties.

In addition, the U.S. Congress has in the past and may in the future consider legislation to reduce emissions of greenhouse gases, and there has been a wide-ranging policy debate, both nationally and internationally, regarding the impact of these gases and possible means for their regulation. Efforts have been made and continue to be made in the international community toward the adoption of international treaties or protocols that would address global climate change issues. In 2015, the United States participated in the United Nations Conference on Climate Change, which led to the creation of the Paris Agreement. The Paris Agreement opened for signing on April 22, 2016 and requires countries to review and “represent a progression” in their intended nationally determined contributions, which set GHG emission reduction goals, every five years beginning in 2020. A number of state and regional efforts have also emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs. These programs typically require major sources of GHG emissions to acquire and surrender emission allowances in return for emitting those GHGs. Any such future laws and regulations imposing reporting obligations on, or limiting emissions of, GHGs could require us to incur costs to reduce emissions of GHGs. Substantial limitations on GHG emissions could also adversely affect demand for oil and natural gas. Depending on the particular program, we could in the future be required to purchase and surrender emission allowances or otherwise undertake measures to reduce greenhouse gas emissions. Any additional costs or operating restrictions associated with new legislation or regulations regarding greenhouse gas emissions could adversely affect the demand for our services and our financial position, results of operations and ability to make cash distributions to unitholders.

Increased regulatory-imposed costs may increase the cost of consuming, and thereby reduce demand for, the products that we gather, treat and transport. To the extent financial markets view climate change and emissions of greenhouse gases as a financial risk, this view could negatively affect our ability to access capital markets or cause us to receive less favorable terms and conditions. Consequently, legislation and regulatory initiatives aimed at reducing greenhouse gases could have a material adverse effect on our financial position, results of operations and ability to make cash distributions to unitholders.

Finally, some scientists have concluded that increasing concentrations of GHGs in the Earth’s atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods and other climatic events; if any such effects were to occur, they could adversely affect our results of operations.

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Our operations are subject to extensive regulation by federal regulatory authorities. Changes or additional regulatory measures adopted by such authorities could adversely affect our financial position, results of operations and ability to make cash distributions to unitholders.

The rates charged by several of our pipeline systems, including for interstate gas transportation service provided by our intrastate pipelines, are regulated by FERC. FERC and state regulatory agencies also regulate other terms and conditions of the services we may offer. If one of these regulatory agencies, on its own initiative or due to challenges by third parties, were to lower our tariff rates or deny any rate increase or other material changes to the types, or terms and conditions, of service we might propose or offer, the profitability of our pipeline businesses could suffer. If we were permitted to raise our tariff rates for a particular pipeline, there might be significant delay between the time the tariff rate increase is approved and the time that the rate increase actually goes into effect, which could also limit our profitability. Furthermore, competition from other pipeline systems may prevent us from raising our tariff rates even if regulatory agencies permit us to do so. The regulatory agencies that regulate our systems periodically implement new rules, regulations and terms and conditions of services subject to their jurisdiction. New initiatives or orders may adversely affect the rates charged for our services or otherwise adversely affect our financial position, results of operations and ability to make cash distributions to our unitholders.

Our natural gas interstate pipelines are regulated by FERC under the Natural Gas Act of 1938, or NGA, the Natural Gas Policy Act of 1978, or the NGPA, and the Energy Policy Act of 2005, or EPAct of 2005. Generally, FERC's authority over interstate natural gas transportation extends to:

- rates, operating terms, conditions of service and service contracts;
- certification and construction of new facilities;
- extension or abandonment of services and facilities or expansion of existing facilities;
- maintenance of accounts and records;
- acquisition and disposition of facilities;
- initiation and discontinuation of services;
- depreciation and amortization policies;
- conduct and relationship with certain affiliates;
- market manipulation in connection with interstate sales, purchases or natural gas transportation; and
- various other matters.

Should we fail to comply with all applicable FERC-administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines. Under EPACT 2005, FERC has civil penalty authority under the NGA and the NGPA to impose penalties for current violations of up to $1 million per day for each violation and possible criminal penalties of up to $1 million per violation.

FERC's jurisdiction extends to the certification and construction of interstate transportation and storage facilities, including, but not limited to expansions, lateral and other facilities and abandonment of facilities and services. Prior to commencing construction of significant new interstate transportation and storage facilities, an interstate pipeline must obtain a certificate authorizing the construction, or an order amending its existing certificate, from FERC. Certain minor expansions are authorized by blanket certificates that FERC has issued by rule. Typically, a significant expansion project requires review by a number of governmental agencies, including state and local agencies, whose cooperation is important in completing the regulatory process on schedule. Any failure by an agency to issue sufficient authorizations or permits in a timely manner for one or more of these projects may mean that we will not be able to pursue these projects or that they will be constructed in a manner or with capital requirements that we did not anticipate. Our inability to obtain sufficient permits and authorizations in a timely manner could materially and negatively impact the additional revenues expected from these projects.

FERC conducts audits to verify compliance with FERC's regulations and the terms of its orders, including whether the websites of interstate pipelines accurately provide information on the operations and availability of services. FERC's regulations require uniform terms and conditions for service, as set forth in agreements for transportation and storage services executed between interstate pipelines and their customers. These service agreements are required to conform, in all material respects, with the standard form of service agreements set forth in the pipeline's FERC-approved tariff. Non-conforming agreements must be filed with, and accepted by, the FERC. In the event that FERC finds that an agreement, in whole or part, is materially non-conforming, it could reject the agreement or require us to seek modification, or alternatively require us to modify our tariff so that the non-conforming provisions are generally available to all customers.

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The rates, terms and conditions for transporting natural gas in interstate commerce on certain of our intrastate pipelines and for services offered at certain of our storage facilities are subject to the jurisdiction of FERC under Section 311 of the NGPA. Rates to provide such interstate transportation service must be “fair and equitable” under the NGPA and are subject to review, refund with interest if found not to be fair and equitable, and approval by FERC at least once every five years.

Our crude oil gathering pipelines are subject to common carrier regulation by FERC under the Interstate Commerce Act, or ICA. The ICA requires that we maintain tariffs on file with FERC setting forth the rates we charge for providing transportation services, as well as the rules and regulations governing such services. The ICA requires, among other things, that our rates must be “just and reasonable” and that we provide service in a manner that is nondiscriminatory. Shippers on our crude oil gathering pipelines may protest our tariff filings, file complaints against our existing rates, or FERC can investigate our rates on its own initiative. In the event that FERC finds that our existing or proposed rates are unjust and unreasonable, it could deny requested rate increases or could order us to reduce our rates and could require the payment of reparations to complaining shippers for up to two years prior to the complaint.

Our operations may also be subject to regulation by state and local regulatory authorities. Changes or additional regulatory measures adopted by such authorities could adversely affect our financial position, results of operations and ability to make cash distributions to unitholders.

Our pipeline operations that are not regulated by FERC may be subject to state and local regulation applicable to intrastate natural and transportation services. The relevant states in which we operate include North Dakota, Oklahoma, Arkansas, Louisiana, Texas, Missouri, Kansas, Mississippi, Tennessee and Illinois. State and local regulations generally focus on safety, environmental and, in some circumstances, prohibition of undue discrimination among shippers. Additional rules and legislation pertaining to these matters are considered and, in some instances, adopted from time to time. We cannot predict what effect, if any, such changes might have on our operations, but we could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes. Other state and local regulations also may affect our business. Any such state or local regulation could have an adverse effect on our business and our financial position, results of operations and ability to make cash distributions to unitholders.

Our gathering lines may be subject to ratable take and common purchaser statutes. Ratable take statutes generally require gatherers to take, without undue discrimination, oil or natural gas production that may be tendered to the gatherer for handling. Similarly, common purchaser statutes generally require gatherers to purchase without undue discrimination as to source of supply or producer. These statutes restrict our right as an owner of gathering facilities to decide with whom we contract to purchase or transport oil or natural gas. Federal law leaves economic regulation of natural gas gathering to the states. The states in which we operate have adopted complaint-based regulation of oil and natural gas gathering activities, which allows oil and natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to access to oil and natural gas gathering pipelines and rate discrimination.

Other state regulations may not directly regulate our business, but may nonetheless affect the availability of natural gas for processing, including state regulation of production rates and maximum daily production allowable from gas wells. While our gathering lines are currently subject to limited state regulation, there is a risk that state laws will be changed, which may give producers a stronger basis to challenge the regulatory status of a line, or the rates, terms and conditions of a gathering line providing transportation service.

A change in the jurisdictional characterization of some of our assets by federal, state or local regulatory agencies or a change in policy by those agencies may result in increased regulation of our assets, which may cause our revenues to decline and operating expenses to increase.

Our natural gas gathering and intrastate transportation operations are generally exempt from the jurisdiction of FERC under the NGA, but FERC regulation may indirectly impact these businesses and the markets for products derived from these businesses. FERC's policies and practices across the range of its oil and natural gas regulatory activities, including, for example, its policies on interstate open access transportation, ratemaking, capacity release, and market center promotion may indirectly affect intrastate markets. In recent years, FERC has pursued pro-competitive policies in its regulation of interstate oil and natural gas pipelines. However, we cannot assure you that FERC will continue to pursue this approach as it considers matters such as pipeline rates and rules and policies that may indirectly affect the intrastate natural gas transportation business. Although FERC has not made a formal determination with respect to all of our facilities we consider to be gathering facilities, management believes that our natural gas gathering pipelines meet the traditional tests that FERC has used to determine that a pipeline is a gathering pipeline and are therefore not subject to FERC jurisdiction. The distinction between FERC-regulated transmission services and federally unregulated gathering services, however, has been the subject of substantial litigation, and FERC determines whether facilities are gathering facilities on a case-by-case basis, so the classification and regulation of our gathering facilities is subject to change based on future

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determinations by FERC, the courts or Congress. If FERC were to consider the status of an individual facility and determine that the facility and/or services provided by it are not exempt from FERC regulation under the NGA and that the facility provides interstate service, the rates for, and terms and conditions of, services provided by such facility would be subject to regulation by FERC under the NGA or the NGPA. Such regulation could decrease revenue, increase operating costs, and, depending upon the facility in question, could adversely affect our financial condition, results of operations and ability to make cash distributions to our unitholders. In addition, if any of our facilities were found to have provided services or otherwise operated in violation of the NGA or NGPA, this could result in the imposition of substantial civil penalties, as well as a requirement to disgorge revenues collected for such services in excess of the maximum rates established by FERC.

Natural gas gathering may receive greater regulatory scrutiny at the state level; therefore, our natural gas gathering operations could be adversely affected should they become subject to the application of state regulation of rates and services. Our gathering operations could also be subject to safety and operational regulations relating to the design, construction, testing, operation, replacement and maintenance of gathering facilities. We cannot predict what effect, if any, such changes might have on our operations, but we could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes.

We may incur significant costs and liabilities resulting from compliance with pipeline safety laws and regulations, pipeline integrity and other similar programs and related repairs.

Our interstate pipeline operations are subject to certain pipeline safety laws and regulations administered by the U.S. Department of Transportation's (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA). 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. Among other things, these laws and regulations require pipeline operators to develop integrity management programs for interstate pipelines located in "high consequence areas." The regulations require operators, including us, to, among other things:

- perform ongoing assessments of pipeline integrity;
- develop a baseline plan to prioritize the assessment of a covered pipeline segment;
- identify and characterize applicable threats that could impact a high consequence area;
- improve data collection, integration, and analysis;
- repair and remediate pipelines as necessary; and
- implement preventive and mitigating action.

Failure to comply with applicable regulations could result in a number of consequences which may have an adverse effect on our operations.

Changes to pipeline safety laws and regulations that result in more stringent or costly safety standards could have a significant adverse effect on us. For example, in August 2011, PHMSA published an advance notice of proposed rulemaking (ANPRM) in which the agency was seeking public comment on a number of changes to regulations governing the safety of gas transmission pipelines and gathering lines, including, for example, revising the definitions of "high consequence areas" and "gathering lines" and strengthening integrity management requirements as they apply to existing regulated operators and to currently exempt operators should certain exemptions be removed. On April 8, 2016, the Pipeline and Hazardous Materials Safety Administration published a notice of proposed rulemaking (NPRM) responding to several of the integrity management topics raised in the August 2011 ANPRM and proposing new requirements to address safety issues for natural gas transmission and gathering lines that have arisen since the issuance of the ANPRM. The proposed rule would strengthen existing integrity management requirements, expand assessment and repair requirements to pipelines in areas with medium population densities, and extend regulatory requirements to onshore gas gathering lines that are currently exempt. Comments were due July 7, 2016. PHMSA issued, but has yet to publish, a similar rule for hazardous liquids (including oil) pipelines on January 13, 2017. This rule extends regulatory reporting requirements to all liquid gathering lines, require additional event-driven and periodic inspections, require use of leak detection systems on all hazardous liquid pipelines, modify repair criteria, and require certain pipelines to eventually accommodate inline inspection tools. It is unclear when or if this rule will go into effect as, on January 20, 2017, the Trump Administration requested that all regulations that had been sent to the Office of the Federal Register, but not yet published, be immediately withdrawn for further review. We are still monitoring and evaluating the effect of these requirements and proposals on our operations.

Although many of our pipelines fall within a class that is currently not subject to regulation by PHMSA, we may incur significant cost and liabilities associated with repair, remediation, preventive or mitigation measures associated with our non-exempt pipelines. This work is part of our normal integrity management program and we do not expect to incur any extraordinary costs during 2017 to complete the testing required by existing PHMSA regulations and their state counterparts. We have not estimated the costs for any repair, remediation, preventive or mitigation actions that may be determined to be necessary as a result of the testing program, which could be substantial, or any lost cash flows resulting from shutting down our pipelines during the pendency of such repairs. Should we fail to comply with PHMSA or comparable state regulations, we could be subject to penalties and fines. In addition, proposed rulemakings such as the NPRMs published on October 13, 2015 and April 8, 2016 could expand the scope of the natural gas and hazardous liquids integrity management programs and other related pipeline safety regulations to include additional requirements or previously exempt pipelines. We have not estimated the cost of complying with such proposed changes to the regulations administered by PHMSA.

Financial reform regulations under the Dodd-Frank Act could adversely affect our ability to use derivative instruments to hedge risks associated with our business.

At times, we may hedge all or a portion of our commodity risk and our interest rate risk. The federal government regulates the derivatives markets and entities, including businesses like ours, that participate in those markets through the Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Dodd-Frank Act, which requires the Commodity Futures Trading Commission, or the CFTC, and the SEC to promulgate rules and regulations implementing the legislation. Under the CFTC's regulations, we are subject to reporting and recordkeeping obligations for transactions involving non-financial swap transactions. The CFTC initially adopted regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents, but these rules were successfully challenged in federal district court by the Securities Industry Financial Markets Association and the International Swaps and Derivatives Association and largely vacated by the court. In December 2013, the CFTC published a Notice of Proposed Rulemaking designed to implement new position limits regulation and in December 2016, the CFTC re-proposal position limits regulations. The ultimate form and timing of the implementation of the regulatory regime affecting commodity derivatives remains uncertain.

The CFTC has imposed mandatory clearing requirements on certain categories of swaps, including certain interest rate swaps, but has exempted derivatives intended to hedge or mitigate commercial risk from the mandatory swap clearing requirement, where the counterparty such as us has a required identification number, is not a financial entity as defined by the regulations, and meets a minimum asset test. Management believes our hedging transactions qualify for this "commercial end-user" exception. The Dodd-Frank Act may also require us to comply with margin requirements in connection with our hedging activities, although the application of those provisions to us is uncertain at this time. The Dodd-Frank Act may also require the counterparties to our derivative instruments to spin off some of their hedging activities to a separate entity, which may not be as creditworthy as the current counterparty.

The Dodd-Frank Act and related regulations could significantly increase the cost of derivatives contracts for our industry (including requirements to post collateral which could adversely affect our available liquidity), materially alter the terms of derivatives contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivatives contracts, and increase our exposure to less creditworthy counterparties, particularly if we are unable to utilize the commercial end user exception with respect to certain of our hedging transactions. If we reduce our use of hedging as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures and fund unitholder distributions. Finally, the legislation was intended, in part, to reduce the volatility of crude oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to crude oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could adversely affect our financial position, results of operations and our ability to make cash distributions to unitholders.

Risks Related to an Investment in Us

Our general partner and its affiliates, including CenterPoint Energy and OGE Energy, have conflicts of interest with us and limited duties to us and our unitholders, and they may favor their own interests to the detriment of us and our other common unitholders.

Affiliates of CenterPoint Energy and OGE Energy own and control our general partner and appoint all of the directors of our general partner. Some of the directors of our general partner are appointed to represent CenterPoint Energy or OGE Energy and are also officers and/or directors of CenterPoint Energy or OGE Energy, respectively. Although our general partner has a duty to manage us in a manner that is beneficial to us and our unitholders, the directors of our general partner who are appointed to represent CenterPoint Energy or OGE Energy have a fiduciary duty to perform their obligations as directors in a manner that is beneficial to CenterPoint Energy or OGE Energy, respectively. Conflicts of interest will arise between CenterPoint Energy, OGE

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Energy and 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 CenterPoint Energy and OGE Energy over our interests and the interests of our unitholders. These conflicts include the following situations, among others:

- Neither the Partnership Agreement nor any other agreement requires CenterPoint Energy or OGE Energy to pursue a business strategy that favors us. The directors and officers of CenterPoint Energy and OGE Energy have a fiduciary duty to make decisions in the best interests of the stockholders of their respective companies, which may be contrary to our interests. CenterPoint Energy and OGE Energy may choose to shift the focus of their investment and growth to areas not served by our assets. In addition, CenterPoint Energy is the holder of our Series A Preferred Units and may favor its interests in voting in favor of actions relating to such units, including voting in favor of making distributions on such Series A Preferred Units even if no distributions are made on the common units.
- Our general partner is allowed to take into account the interests of parties other than us, such as CenterPoint Energy and OGE Energy, in resolving conflicts of interest.
- Some of the directors of our general partner are also officers and/or directors of CenterPoint Energy or OGE Energy and will owe fiduciary duties to their respective companies. These individuals may also devote significant time to the business of CenterPoint Energy and OGE Energy.
- The Partnership Agreement replaces the fiduciary duties that would otherwise be owed to us by our general partner with contractual standards governing its duties, limits our general partner's liabilities and restricts the remedies available to our unitholders for actions that, without such limitations, might constitute breaches of fiduciary duty.
- Except in limited circumstances, our general partner has the power and authority to conduct our business without unitholder approval.
- Disputes may arise under our commercial agreements with CenterPoint Energy and OGE Energy.
- Our general partner determines the amount and timing of asset purchases and sales, borrowings, issuances of additional partnership units and the creation, reduction or increase of cash reserves, each of which can affect the amount of distributable cash flow.
- Our general partner determines the amount and timing of any capital expenditures and whether a capital expenditure is classified as a maintenance capital expenditure, which reduces operating surplus, or an expansion or investment capital expenditure, which does not reduce operating surplus. This determination can affect the amount of cash that is distributed to our unitholders and the ability of the subordinated units to convert to common units.
- Our general partner determines which costs incurred by it and its affiliates are reimbursable by us.
- 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 a distribution on the subordinated units, to make incentive distributions or to accelerate the expiration of the subordination period.
- The Partnership Agreement permits us to classify up to $300 million as operating surplus, even if it is generated from asset sales, non-working capital borrowings or other sources that would otherwise constitute capital surplus. This cash may be used to fund distributions on our subordinated or general partner units or to our general partner in respect of the incentive distribution rights.
- The Partnership Agreement does not prohibit our general partner from causing us to pay it or its 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.
- Our general partner may exercise its right to call and purchase all of the common units not owned by it and its affiliates if they own more than 90% of the common units. If our general partner and its affiliates reduce their ownership percentage to below 70% of the outstanding units, the ownership threshold to exercise the call right will be permanently reduced to 80%.
- Our general partner controls the enforcement of the obligations that it and its affiliates owe to us.
- Our general partner decides whether to retain separate counsel, accountants or others to perform services for us.
- Our general partner may transfer its incentive distribution rights without unitholder approval.
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Our general partner may elect to cause us to issue common units to it in connection with a resetting of the target distribution levels related to our general partner's incentive distribution rights without the approval of the conflicts committee of the Board of Directors or our unitholders. This election may result in lower distributions to our common unitholders in certain situations.

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If a unitholder is not an Eligible Holder, the unitholder's common units may be subject to redemption.

Our partnership agreement includes certain requirements regarding those investors who may own our common, subordinated, and preferred units. Eligible Holders are limited partners whose (i) federal income tax status is not reasonably likely to have a material adverse effect on the rates that can be charged by us on assets that are subject to regulation by FERC or an analogous regulatory body and (ii) nationality, citizenship or other related status would not create a substantial risk of cancellation or forfeiture of any property in which we have an interest, in each case as determined by our general partner with the advice of counsel. If the unitholder is not an Eligible Holder, in certain circumstances as set forth in our partnership agreement, the unitholder's units may be redeemed by us at 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.

Our partnership agreement requires that we distribute all of our available cash, which could limit our ability to grow and make acquisitions.

Our partnership agreement requires that we distribute all of our available cash to our unitholders and will rely primarily upon external financing sources, including commercial borrowings and the issuance of debt and equity securities, to fund our acquisitions and expansion capital expenditures. As a result, to the extent we are unable to finance growth externally, our cash distribution policy will significantly impair our ability to grow.

In addition, because we intend to distribute all of our available cash, our growth may not be as fast as that of businesses that reinvest their available cash to expand ongoing operations. To the extent we issue additional units in connection with any acquisitions or expansion capital expenditures, the payment of distributions on those additional units may increase the risk that we will be unable to maintain or increase our per unit distribution level. There are no limitations in our partnership agreement or in our credit facilities that limit our ability to issue additional units, including units ranking senior to the common units. The incurrence of additional commercial borrowings or other debt to finance our growth strategy would result in increased interest expense, which in turn may impact the available cash that we have to distribute to our unitholders.

The reimbursements due to our general partner and its affiliates for services provided to us or on our behalf will reduce our distributable cash flow. The amount and timing of such reimbursements will be determined by our general partner.

Prior to making any distribution on our common units, we will reimburse our general partner and its affiliates, including CenterPoint Energy and OGE Energy, for costs and expenses they incur and payments they make on our behalf. Pursuant to services agreements we have entered into with each of CenterPoint Energy and OGE Energy, we will reimburse CenterPoint Energy and OGE Energy for the payment of operating expenses related to our operations and for the provision of various general and administrative services performed for our benefit. Payments for these services may be substantial and will reduce the amount of distributable cash flow. Additionally, we will reimburse CenterPoint Energy and OGE Energy for direct or allocated costs and expenses incurred on our behalf, including administrative costs, such as compensation expense for those persons who provide services necessary to run our business, and insurance expenses. Our partnership agreement provides that our general partner will determine in good faith the expenses that are allocable to us. The reimbursement of expenses and payment of fees, if any, to our general partner and its affiliates will reduce the amount of available cash to pay cash distributions to our common unitholders.

Any reductions in our credit ratings could increase our financing costs and the cost of maintaining certain contractual relationships.

We cannot assure you that our credit ratings will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances warrant. On February 2, 2016, Standard & Poor’s Ratings Services lowered its credit rating on the Partnership from an investment grade rating to a non-investment grade rating. The short-term rating on the Partnership was also reduced from an investment grade rating to a non-investment grade rating. As a result of the downgrade, the Partnership repaid its outstanding borrowings under the commercial paper program upon maturity and did not issue any additional commercial paper. If either, or both, of Moody’s Investors Service or Fitch Ratings lowers its credit ratings of the Partnership from an investment grade rating to a non-investment grade rating while our rating from Standard & Poor’s Ratings Services is below investment grade, the cost of our borrowings will increase. So long as any of our credit ratings are below investment grade, we may have higher future borrowing costs and we or our subsidiaries may be required to post cash collateral or letters of credit under certain contractual agreements. If cash collateral requirements were to occur at a time when we were experiencing significant working capital requirements or otherwise lacked liquidity, our financial position, results of operations and ability to make cash distributions to unitholders could be adversely affected.

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The credit and business risk profiles and the business plans of our sponsors, CenterPoint Energy and OGE Energy, could adversely affect our credit ratings and profile.

The credit and business risk profiles and the business plans of our sponsors, CenterPoint Energy and OGE Energy, may be factors in credit evaluations of us because, through their indirect ownership of our general partner, they can influence our business activities, including our cash distribution strategy, acquisition strategy, and business risk profile. The financial conditions of CenterPoint Energy and OGE Energy, including the degree of their financial leverage and their dependence on cash flows from us, as well as their business plans with respect to their investment in us, may be considered by credit rating agencies in their assessment of our credit ratings and profile.

CenterPoint Energy and OGE Energy, which indirectly own our general partner, have indebtedness outstanding and are partially dependent on the cash distributions from their general partner and limited partner interests in us to service such indebtedness and pay dividends on their common stock. Any distributions by us to such entities will be made only after satisfying our then-current obligations to our creditors. Our credit ratings and business risk profile could be adversely affected if the ratings and risk profiles of the entities that control our general partner were viewed as substantially lower or more risky than ours.

Our partnership agreement replaces our general partner’s fiduciary duties to holders of our common units with contractual standards governing its duties.

Our partnership agreement contains provisions that eliminate the fiduciary standards to which our general partner would otherwise be held by state fiduciary duty law and replaces those duties with several different contractual standards. 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, free of any duties to us and our unitholders other than the implied contractual covenant of good faith and fair dealing, which means that a court will enforce the reasonable expectations of the partners where the language in the partnership agreement does not provide for a clear course of action. This provision entitles our general partner to consider only the interests and factors that it desires and relieves it of any duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or our limited partners. Examples of decisions that our general partner may make in its individual capacity include:

- how to allocate corporate opportunities among us and its other affiliates;
- whether to exercise its limited call right;
- whether to seek approval of the resolution of a conflict of interest by the conflicts committee of the Board of Directors;
- whether to elect to reset target distribution levels;
- whether to transfer the incentive distribution rights to a third party; and
- whether or not to consent to any merger or consolidation of the Partnership or amendment to the partnership agreement.

By purchasing a common unit, a common unitholder agrees to become bound by the provisions in the partnership agreement, including the provisions discussed above.

Our partnership agreement 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 restrict the remedies available to unitholders for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty under state fiduciary duty law. For example, our partnership agreement provides that:

- whenever our general partner, the Board of Directors or any committee thereof (including the conflicts committee) makes a determination or takes, or declines to take, any other action in their respective capacities, our general partner, the Board of Directors and any committee thereof (including the conflicts committee), as applicable, is required to make such determination, or take or decline to take such other action, in good faith, meaning that it subjectively believed that the decision was in the best interests of the Partnership, and, except as specifically provided by our partnership agreement, will not be subject to any other or different standard imposed by our partnership agreement, Delaware law, or any other law, rule or regulation, or at equity;

- 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 such decisions are made in good faith;
- our general partner and its officers and directors will not be liable for monetary damages to us or our limited partners resulting from any act or omission unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that our general partner or its officers and directors, as the case may be, acted in

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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

- our general partner will not be in breach of its obligations under the partnership agreement (including any duties to us or our unitholders) if a transaction with an affiliate or the resolution of a conflict of interest is:
- approved by the conflicts committee of the Board of Directors, although our general partner is not obligated to seek such approval;
- approved by the vote of a majority of the outstanding common units, excluding any common units owned by our general partner and its affiliates;
- determined by the Board of Directors to be on terms no less favorable to us than those generally being provided to or available from unrelated third parties; or
- determined by the Board of Directors to be fair and reasonable to us, taking into account the totality of the relationships among the parties involved, including other transactions that may be particularly favorable or advantageous to us.

In connection with a situation involving a transaction with an affiliate or a conflict of interest, any determination by our general partner or the conflicts committee must be made in good faith. If an affiliate transaction or the resolution of a conflict of interest is not approved by our common unitholders or the conflicts committee and the Board of Directors determines that the resolution or course of action taken with respect to the affiliate transaction or conflict of interest satisfies either of the standards set forth in the third and fourth subbullets above, then it will be presumed that, in making its decision, the Board of Directors acted in good faith, and in any proceeding brought by or on behalf of any limited partner or the Partnership challenging such determination, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption.

Our general partner may elect to cause us to issue common units to it in connection with a resetting of the minimum quarterly distribution and the target distribution levels related to our general partner’s incentive distribution rights without the approval of the conflicts committee of our general partner or our unitholders. This may result in lower distributions to our common unitholders in certain situations.

Our general partner has the right, at any time when there are no subordinated units outstanding, if it has received incentive distributions at the highest level to which it is entitled (50%) for each of the prior four consecutive fiscal quarters and the amount of each such distribution did not exceed the adjusted operating surplus for such quarter, respectively, to reset the initial minimum quarterly distribution and cash target distribution levels at higher levels based on the average cash distribution amount per common unit for the two fiscal quarters prior to the exercise of the reset election. Following a reset election by our general partner, the minimum quarterly distribution amount will be reset to an amount equal to the average cash distribution amount per common unit for the two fiscal quarters immediately preceding the reset election (such amount is referred to as the reset minimum quarterly distribution) and the target distribution levels will be reset to correspondingly higher levels based on percentage increases above the reset minimum quarterly distribution amount.

We anticipate that our general partner would exercise this reset right in order to facilitate acquisitions or internal growth projects that would not be sufficiently accretive to cash distributions per common unit without such conversion; however, it is possible that our general partner could exercise this reset election at a time when we are experiencing declines in our aggregate cash distributions or at a time when our general partner expects that we will experience declines in our aggregate cash distributions in the foreseeable future. In such situations, our general partner may be experiencing, or may be expected to experience, declines in the cash distributions it receives related to its incentive distribution rights and may therefore desire to be issued our common units, which are entitled to specified priorities with respect to our distributions and which therefore may be more advantageous for the general partner to own in lieu of the right to receive incentive distribution payments based on target distribution levels that are less certain to be achieved in the then-current business environment. This risk could be elevated if our incentive distribution rights have been transferred to a third party. Our general partner has the right to transfer the incentive distribution rights at any time, in whole or in part, and any transferee holding a majority of the incentive distribution rights shall have the same rights as our general partner with respect to resetting target distributions. As a result, a reset election may cause our common unitholders to experience dilution in the amount of cash distributions that they would have otherwise received had we not issued new common units to our general partner in connection with resetting the target distribution levels related to our general partner incentive distribution rights.

Holders of our common units have limited voting rights and are not entitled to elect our general partner or its directors.

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 have no right to elect our general partner or its Board of Directors on an annual or other continuing basis. Because CenterPoint Energy and OGE

Energy collectively indirectly own 100% of our general partner, the Board of Directors has been, and, as long as CenterPoint Energy and OGE Energy own 100% of our general partner, will continue to be, chosen by CenterPoint Energy and OGE Energy. Furthermore, if the unitholders were dissatisfied with the performance of our general partner, they will have little ability to remove our general partner. Please see "—Even if holders of our common units are dissatisfied, they will not be able to remove our general partner without its consent." 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. 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.

Even if holders of our common units are dissatisfied, they will not be able to remove our general partner without its consent.

The unitholders are unable to remove our general partner without its consent because affiliates of our general partner own sufficient units to be able to prevent its removal. The vote of the holders of at least 75% of all outstanding units voting together as a single class is required to remove our general partner. As of February 1, 2017, affiliates of our general partner owned 79.8% of our aggregate outstanding common and subordinated units. Also, if our general partner is removed without cause during the subordination period and units held by our general partner and its affiliates are not voted in favor of that removal, all remaining subordinated units will automatically convert into common units and any existing arrearages on our common units will be extinguished. A removal of our general partner under these circumstances would adversely affect our common units by prematurely eliminating their distribution and liquidation preference over our subordinated units, which would otherwise have continued until we had met certain distribution and performance tests. "Cause" is narrowly defined under our partnership agreement to mean that a court of competent jurisdiction has entered a final, non-appealable judgment finding our general partner liable for actual fraud or willful misconduct in its capacity as our general partner. "Cause" does not include most cases of charges of poor management of the business, so the removal of our general partner because of the unitholders' dissatisfaction with our general partner's performance in managing us will most likely result in the termination of the subordination period and conversion of all subordinated units to common units.

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

Unitholders' voting rights are further restricted by a provision of our partnership agreement 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, cannot vote on any matter.

Our general partner's interest in us and 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 our unitholders. Our partnership agreement does not restrict the ability of the owners of our general partner from transferring all or a portion of their respective limited liability company interest in our general partner to a third party. The new owners of our general partner would then be in a position to replace the Board of Directors and officers of our general partner with its own choices and thereby influence the decisions taken by the Board of Directors and officers.

The incentive distribution rights of our general partner may be transferred to a third party without unitholder consent.

Our general partner may transfer its incentive distribution rights to a third party at any time without the consent of our unitholders. If our general partner transfers its incentive distribution rights to a third party but retains its general partner interest, our general partner may not have the same incentive to grow the Partnership and increase quarterly distributions to unitholders over time as it would if it had retained ownership of its incentive distribution rights. For example, a transfer of incentive distribution rights by our general partner could reduce the likelihood of CenterPoint Energy or OGE Energy selling or contributing additional assets to us, as they would have less of an economic incentive to grow our business, which in turn would impact our ability to grow our asset base.

We may issue additional units without your approval, which would dilute your existing ownership interests.

The Partnership Agreement does not limit the number of additional limited partner interests, including limited partner interests that rank senior to the common units, 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:

- our existing unitholders’ proportionate ownership interest in us will decrease;

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- the amount of distributable cash flow on each unit may decrease;
- because a lower percentage of total outstanding units will be subordinated units, the risk that a shortfall in the payment of the minimum quarterly distribution will be borne by our common unitholders will increase;
- because the amount payable to holders of incentive distribution rights is based on a percentage of the total distributable cash flow, the distributions to holders of incentive distribution rights will increase even if the per unit distribution on common units remains the same;
- 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.

In addition, upon a change of control or certain fundamental transactions, our Series A Preferred Units are convertible into common units at the option of the holders of such units. If a substantial portion of the Series A Preferred Units were converted into common units, common unitholders could experience significant dilution. In addition, if holders of such converted Series A Preferred Units were to dispose of a substantial portion of these common units in the public market, whether in a single transaction or series of transactions, it could adversely affect the market price for our common units. In addition, these sales, or the possibility that these sales may occur, could make it more difficult for us to sell our common units in the future.

Affiliates of our general partner may sell common units in the public or private markets, which could have an adverse impact on the trading price of the common units.

As of February 1, 2017, subsidiaries of CenterPoint Energy and OGE Energy held an aggregate of 136,983,998 common units and 207,855,430 subordinated units and CenterPoint Energy held 14,520,000 Series A Preferred Units. Upon a change of control or certain fundamental transactions, our Series A Preferred Units are convertible into common units at the option of the holders of such units. All of the subordinated units will convert into common units at the end of the subordination period and some may convert earlier under certain circumstances. In addition, we have agreed to provide CenterPoint Energy, OGE Energy and ArcLight with certain registration rights. The sale of these units in the public or private markets could have an adverse impact 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 unitholders to sell their units at an undesirable time or price.

If at any time our general partner and its affiliates own more than 90% of our common units, our general partner will have the right, which it may assign to any of its affiliates or to us, but not the obligation, 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 calculated pursuant to the terms of the Partnership Agreement. If our general partner and its affiliates reduce their ownership percentage to below 70% of the outstanding units, the ownership threshold to exercise the call right will be permanently reduced to 80%. As a result, our unitholders may be required to sell their common units at an undesirable time or price and may not receive any positive return on their investment. Our unitholders may also incur a tax liability upon any such sale of their units. As of February 1, 2017, affiliates of our general partner owned approximately 61.0% of our outstanding common units. At the end of the subordination period, assuming no additional issuances of common units (other than upon the conversion of the subordinated units), affiliates of our general partner will own approximately 79.8% of our aggregate outstanding common units. If we assume the conversion of our Series A Preferred Units using the closing price of our units as of February 1, 2017, affiliates of our general partner will then own 80.8% of our aggregate outstanding common units. Affiliates of our general partner may acquire additional common units from us in connection with future transactions or through open-market or negotiated purchases.

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. The Partnership is organized under Delaware law, and we 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 other states in which we may do business. Our unitholders could be held liable for any and all of our obligations as if they were general partners if a court or government agency were to determine that:

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

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Our partnership agreement designates the Court of Chancery of the State of Delaware as the exclusive forum for certain types of actions and proceedings that may be initiated by our unitholders, which limits our unitholders' ability to choose the judicial forum for disputes with us or our general partner's directors, officers or other employees.

Our partnership agreement provides, that, with certain limited exceptions, the Court of Chancery of the State of Delaware is the exclusive forum for any claims, suits, actions or proceedings (1) arising out of or relating in any way to our partnership agreement (including any claims, suits or actions to interpret, apply or enforce the provisions of our partnership agreement or the duties, obligations or liabilities among our partners, or obligations or liabilities of our partners to us, or the rights or powers of, or restrictions on, our partners or us), (2) brought in a derivative manner on our behalf, (3) asserting a claim of breach of a duty (including a fiduciary duty) owed by any of our, or our general partner's, directors, officers, or other employees, or owed by our general partner, to us or our partners, (4) asserting a claim against us arising pursuant to any provision of the Delaware Revised Uniform Limited Partnership Act or (5) asserting a claim against us governed by the internal affairs doctrine. Any person or entity purchasing or otherwise acquiring any interest in our common units is deemed to have received notice of and consented to the foregoing provisions. Although management believes this choice of forum provision benefits us by providing increased consistency in the application of Delaware law in the types of lawsuits to which it applies, the provision may have the effect of discouraging lawsuits against us and our general partner's directors and officers. The enforceability of similar choice of forum provisions in other companies' certificates of incorporation or similar governing documents has been challenged in legal proceedings and it is possible that in connection with any action a court could find the choice of forum provisions contained in our partnership agreement to be inapplicable or unenforceable in such action. If a court were to find this choice of forum provision inapplicable to, or unenforceable in respect of, one or more of the specified types of actions or proceedings, we may incur additional costs associated with resolving such matters in other jurisdictions, which could adversely affect our financial position, results of operations and ability to make cash distributions to our unitholders.

The NYSE does not require a publicly traded limited partnership like us to comply with certain of its corporate governance requirements.

Our common units are listed on the NYSE. Because we are a publicly traded limited partnership, the NYSE does not require us to have, and we do not intend to have, a majority of independent directors on our Board of Directors, to establish a nominating and corporate governance committee, or to have a compensation committee composed entirely of independent directors. Accordingly, unitholders will not have the same protections afforded to certain corporations that are subject to all of the NYSE corporate governance requirements.

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, which we refer to herein as the Delaware Act, we may not make a distribution to our unitholders 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. Transferees of common units are liable for both the obligations of the transferor to make contributions to the Partnership that are known to the transferee at the time of transfer and for unknown obligations if the liabilities could have been determined from the partnership agreement. Neither liabilities to partners on account of their partnership interest nor liabilities that are non-recourse to the Partnership are counted for purposes of determining whether a distribution is permitted.

Our general partner intends to limit its liability regarding our obligations.

Our general partner intends to limit its liability under contractual arrangements so that the counterparties to such arrangements have recourse only against our assets and not against our general partner or its assets. Our general partner may therefore cause us to incur indebtedness or other obligations that are non-recourse to our general partner. Our partnership agreement permits our general partner to limit its liability, even if we could have obtained more favorable terms without the limitation on liability. In addition, we are obligated to reimburse or indemnify our general partner to the extent that it incurs obligations on our behalf. Any such reimbursement or indemnification payments would reduce the amount of cash otherwise available for distribution to our unitholders.

An increase in interest rates could adversely impact the price of our common units, our ability to issue equity or incur debt for acquisitions or other purposes and our ability to make cash distributions at our intended levels.

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, the market price of our common units is impacted by the level of our cash distributions and implied distribution yield. The distribution yield is often used by investors to compare and rank related yield-oriented securities for investment decision purposes. 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 impact on the price of our common units, our ability to issue additional equity to make acquisitions or for other purposes, our financial position, results of operations and our ability to make cash distributions at our intended levels.

Our Series A Preferred Units have rights, preferences and privileges that are not held by, and are preferential to the rights of, holders of our common units.

Our Series A Preferred Units rank senior to all of our other classes or series of equity securities with respect to distribution rights and rights upon liquidation. We cannot declare or pay a distribution to our common or subordinated unitholders for any quarter unless full distributions have been or contemporaneously are being paid on all outstanding Series A Preferred Units for such quarter. These preferences could adversely affect the market price for our common units, or could make it more difficult for us to sell our common units in the future.

Holders of the Series A Preferred Units will receive, on a non-cumulative basis and if and when declared by our general partner, a quarterly cash distribution, subject to certain adjustments, equal to an annual rate of 10% on the stated liquidation preference from the date of original issue to, but not including, the five year anniversary of the original issue date, and an annual rate of LIBOR plus a spread of 850 bps on the stated liquidation preference thereafter. In connection with certain transfers of the Series A Preferred Units, the Series A Preferred Units will automatically convert into one or more new series of preferred units (the “other preferred units”) on the later of the date of transfer or the second anniversary of the date of issue. The other preferred units will have the same terms as our Series A Preferred Units except that unpaid distributions on the other preferred units will accrue from the date of their issuance on a cumulative basis until paid. Our Series A Preferred Units are convertible into common units by the holders of such units in certain circumstances. Payment of distributions on our Series A Preferred Units, or on the common units issued following the conversion of such Series A Preferred Units, could impact our liquidity and reduce the amount of cash flow available for working capital, capital expenditures, growth opportunities, acquisitions, and other general partnership purposes. Our obligations to the holders of Series A Preferred Units could also limit our ability to obtain additional financing or increase our borrowing costs, which could have an adverse effect on our financial condition.

Our Series A Preferred Units contain covenants that may limit our business flexibility.

Our Series A Preferred Units contain covenants preventing us from taking certain actions without the approval of the holders of 66 2⁄3% of the Series A Preferred Units. The need to obtain the approval of holders of the Series A Preferred Units before taking these actions could impede our ability to take certain actions that management or our board of directors may consider to be in the best interests of our unitholders. The affirmative vote of 66 2⁄3% of the outstanding Series A Preferred Units, voting as a single class, is necessary to amend the Partnership Agreement in any manner that would or could reasonably be expected to have a material adverse effect on the rights, preferences, obligations or privileges of the Series A Preferred Units. The affirmative vote of 66 2⁄3% of the outstanding Series A Preferred Units and any outstanding series of other preferred units, voting as a single class, is necessary to (A) create or issue certain party securities with proceeds in an aggregate amount in excess of $700 million or create or issue any senior securities or (B) subject to our right to redeem the Series A Preferred Units, approve certain fundamental transactions.

Our Series A Preferred Units are required to be redeemed in certain circumstances if they are not eligible for trading on the NYSE, and we may not have sufficient funds to redeem our Series A Preferred Units if we are required to do so.

The holders of our Series A Preferred Units may request that we list those units for trading on the NYSE. If we are unable to list the Series A Preferred Units in certain circumstances, we will be required to redeem the Series A Preferred Units. There can be no assurance that we would have sufficient financial resources available to satisfy our obligation to redeem the Series A Preferred Units. In addition, mandatory redemption of our Series A Preferred Units could adversely affect our financial position, results of operations and ability to make cash distributions to unitholders.

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Tax Risks to Common Unitholders

Our tax treatment depends on our status as a partnership for federal income tax purposes. If the IRS were to treat us as a corporation for federal income tax purposes, which would subject us to entity-level taxation, then our distributable cash flow to our unitholders would be substantially reduced.

The anticipated after-tax economic benefit of an investment in the common units depends largely on our being treated as a partnership for federal income tax purposes. We have not requested a ruling from the Internal Revenue Service, or IRS, regarding our qualification as a partnership for tax purposes.

Despite the fact that we are a limited partnership under Delaware law, it is possible in certain circumstances for a partnership such as ours to be treated as a corporation for federal income tax purposes. A change in our business or a change in current law could cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to taxation as an entity.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate, which is currently a maximum of 35.0%, and would likely pay state and local income tax at varying rates. Distributions to our unitholders would generally be taxed again as corporate dividends (to the extent of our current and accumulated earnings and profits), and no income, gains, losses, deductions, or credits would flow through to such unitholders. Because a tax would be imposed upon us as a corporation, our distributable cash flow to our unitholders would be substantially reduced. Therefore, if we were treated as a corporation for federal income tax purposes there would be material reductions in the anticipated cash flow and after-tax return to our unitholders, likely causing a substantial reduction in the value of our common units. This could adversely affect our financial position, results of operations and ability to make cash distributions to unitholders.

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

If we were subjected to a material amount of additional entity-level taxation by individual states, it would reduce our distributable cash flow to our unitholders.

Changes in current state law may subject us to additional entity-level taxation by individual states. 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. Imposition of such additional tax on us by a state will reduce the distributable cash flow. Our partnership agreement provides that, if a law is enacted or an existing law is modified or interpreted in a manner that subjects us to entity-level taxation, the minimum quarterly distribution amount and the target distribution amounts may be adjusted to reflect the impact of that law on us.

The 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 of applicable law, 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, legislative or judicial interpretation at any time. From time to time, members of the U.S. Congress propose and consider substantive changes to the existing federal income tax laws that affect publicly traded partnerships.

Additionally, on January 24, 2017, final regulations by the IRS and the U.S. Department of the Treasury were published in the Federal Register that provide industry-specific guidance regarding whether income earned from certain activities will constitute qualifying income. We believe that we will continue to be able to meet the exception for us to be treated as a partnership for U.S. federal income tax purposes under the new rules. However, any other modification to the federal income tax laws and interpretations thereof could make it more difficult or impossible to meet such exception. We are unable to predict whether any such changes will ultimately be enacted, but it is possible that a change in law could affect us and may, if enacted, be applied retroactively. Any such changes could negatively impact the value of an investment in our common units.

Our unitholders’ share of our income will be taxable to them for U.S. federal income tax purposes even if they do not receive any cash distributions from us.

Because a unitholder will be treated as a partner to whom we will allocate taxable income which could be different in amount than the cash we distribute, a unitholder’s allocable share of our taxable income will be taxable to it, which may require the payment of federal income taxes and, in some cases, state and local income taxes on such unitholder’s share of our taxable income even if

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it receives no cash distributions from us. Our unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability that results from that income.

In response to current market conditions, we may engage in transactions to deliver and manage our liquidity that may result in income and gain to our unitholders without a corresponding cash distribution. For example, if we sell assets and use the proceeds to repay existing debt or fund capital expenditures, our unitholders may be allocated taxable income and gain resulting from the sale without receiving a cash distribution. Further, taking advantage of opportunities to reduce our existing debt, such as debt exchanges, debt repurchases, or modifications of our existing debt could result in "cancellation of indebtedness income" (also referred to as "COD income") being allocated to our unitholders as taxable income. Unitholders may be allocated COD income, and income tax liabilities arising therefrom may exceed cash distributions. The ultimate effect of any such allocations will depend on the unitholder's individual tax position with respect to its units. Unitholders are encouraged to consult their tax advisors with respect to the consequences to them of COD income.

If the IRS contests the federal income tax positions we take, the market for our common units may be adversely impacted and the cost of any IRS contest would likely reduce our distributable cash flow to unitholders.

We have not requested a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes. The IRS may adopt positions that differ from the conclusions of our counsel expressed in a prospectus or from the positions we take, and the IRS's positions may ultimately be sustained. 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 and such positions may not ultimately be sustained. A court may not agree with some or all of our counsel's conclusions or the positions we take. Any contest with the IRS, and the outcome of any IRS contest, may have a materially adverse effect on the market for our common units and the price at which they trade. In addition, our costs of any contest with the IRS would be borne indirectly by our unitholders and our general partner because the costs would likely reduce our distributable cash flow to our unitholders.

If the IRS makes audit adjustments to our income tax returns for tax years beginning after 2017, the IRS (and some states) may collect any resulting taxes (including any applicable penalties and interest) directly from us, in which case our cash available for distribution to our unitholders might be substantially reduced.

Pursuant to the Bipartisan Budget Act of 2015, if the IRS makes audit adjustments to our income tax returns for tax years beginning after 2017, it may collect any resulting taxes (including any applicable penalties and interest) directly from us. We will generally have the ability to shift any such tax liability to our general partner and our unitholders in accordance with their interests in us during the year under audit, but there can be no assurance that we will be able to do so (and will choose to do so) under all circumstances, or that we will be able to (or choose to) effect corresponding shifts in state income or similar tax liability resulting from the IRS adjustment in states in which we do business in the year under audit or in the adjustment year. If we make payments of taxes, penalties and interest resulting from audit adjustments, our cash available for distribution to our unitholders might be substantially reduced. In addition, because payment would be due during the year in which the audit is completed, unitholders during that year would bear the burden of the adjustment even if they were not unitholders during the audited taxable year.

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

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

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

Investment in our common units by tax-exempt entities, such as employee benefit plans and individual retirement accounts (known as IRAs), and non-U.S. persons raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income (UBTI) and will be taxable to the exempt organization as UBTI on the exempt organization's tax return in the year

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the exempt organization is allocated the income. Distributions to non-U.S. persons will be reduced by withholding taxes at the highest applicable effective tax rate, and non-U.S. persons will be required to file U.S. federal income tax returns and pay tax on their share of our taxable income. If you are a tax-exempt entity or a non-U.S. person, you should consult a tax advisor before investing in our common units.

We treat each holder of our common units as having the same tax benefits without regard to the actual common units held. 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 will adopt depreciation and amortization positions that may not conform to all aspects of existing Treasury Regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to our unitholders. A successful IRS challenge also could affect the timing of these tax benefits or the amount of gain from a unitholder’s sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to such unitholder’s tax returns.

We prorate our items of income, gain, loss and deduction for U.S. 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, instead of on the basis of the date a particular unit is transferred. The IRS may challenge this treatment, which could change the allocation of items of income, gain, loss and deduction among our unitholders.

We prorate our items of income, gain, loss and deduction for U.S. 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, instead of on the basis of the date a particular unit is transferred. The U.S. Department of the Treasury recently adopted final Treasury Regulations allowing a similar monthly simplifying convention, for taxable years beginning on or after August 3, 2015. However, such final regulations do not specifically authorize the use of the proration method we have adopted. If the IRS were to challenge our proration method or new Treasury regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.
A unitholder whose common units are loaned to a “short seller” to cover a short sale of common units may be considered as having disposed of those common units. If so, such unitholder would no longer be treated for federal income tax purposes as a partner with respect to those common units during the period of the loan and may recognize gain or loss from the disposition.

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

We have adopted certain valuation methodologies and monthly conventions for U.S. federal income tax purposes that may result in a shift of income, gain, loss and deduction between our general partner and our 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 will determine the fair market value of our assets and allocate any unrealized gain or loss attributable to our assets to the capital accounts of our 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 our general partner, which may be unfavorable to such unitholders. Moreover, under our valuation methods, 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 our tangible and intangible assets, and allocations of taxable income, gain, loss and deduction between our general partner and certain of our unitholders.

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

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The sale or exchange of 50% or more of our capital and profits interests during any 12-month period will result in the termination of the Partnership for federal income tax purposes.

We will be considered to have technically terminated the Partnership for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a 12-month period. For purposes of determining whether the 50% threshold has been met, multiple sales of the same interest will be counted only once. Our technical termination would, among other things, result in the closing of our taxable year for all unitholders, which would result in us filing two tax returns (and our unitholders could receive two Schedules K-1 if relief was not available, as described below) for one fiscal year if the termination occurs on a day other than December 31 and could result in a deferral of depreciation deductions allowable in computing our taxable income. In the case of a unitholder reporting on a taxable year other than a fiscal year ending December 31, the closing of our taxable year may also result in more than 12 months of our taxable income or loss being includable in such unitholder's taxable income for the year of termination. Our termination currently would not affect our classification as a partnership for federal income tax purposes, but instead we would be treated as a new partnership for tax purposes. If treated as a new partnership, we must make new tax elections and could be subject to penalties if we are unable to determine that a termination occurred. The IRS has announced a publicly traded partnership technical termination relief program whereby, if a publicly traded partnership that technically terminated requests publicly traded partnership technical termination relief and such relief is granted by the IRS, among other things, the Partnership will only have to provide one Schedule K-1 to unitholders for the year notwithstanding two partnership tax years.

As a result of investing in our common units, our unitholders will likely be subject to state and local taxes and return filing requirements in jurisdictions where we operate or own or acquire properties.

In addition to federal income taxes, our unitholders will likely be subject to other taxes, including state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we conduct business or own property now or in the future, even if they do not live in any of those jurisdictions. Our unitholders will likely be required to file state and local income tax returns and pay state and local income taxes in some or all of these various jurisdictions. Further, our unitholders may be subject to penalties for failure to comply with those requirements. We currently own property and conduct business in a number of states, most of which currently impose a personal income tax on individuals, and most of which also impose an income or similar tax on corporations and certain other entities. As we make acquisitions or expand our business, we may own property or conduct business in additional states that impose an income tax or similar tax. In certain states, tax losses may not produce a tax benefit in the year incurred and also may not be available to offset income in subsequent tax years. Some states may require us, or we may elect, to withhold a percentage of income from amounts to be distributed to a unitholder who is not a resident of the state. Withholding, the amount of which may be greater or less than a particular unitholders' income tax liability to the state, generally does not relieve a nonresident unitholder from the obligation to file an income tax return. Amounts withheld may be treated as if distributed to unitholders for purposes of determining the amounts distributed by us.

Compliance with and changes in tax laws could adversely affect our performance.

We are subject to extensive tax laws and regulations, including federal and state income taxes and transactional taxes such as excise, sales/use, payroll, franchise and ad valorem taxes. New tax laws and regulations and changes in existing tax laws and regulations are continuously being enacted that could result in increased tax expenditures in the future. Many of these tax liabilities are subject to audits by the respective taxing authority. These audits may result in additional taxes as well as interest and penalties.

Item 1B. Unresolved Staff Comments.

None.

Item 2. Properties

For descriptions of our gathering systems, processing plants, transportation systems and storage facilities, please see Item 1. “Business—Our Assets and Operations.” Our real property falls into two categories: (i) property that we own in fee and (ii) property that we have the right to use under leases, easements, rights-of-way, permits or licenses. Our processing plants are located on property we own in fee, other than Roger Mills which is located on property that we use under lease. Our other gathering and processing assets and transportation and storage assets are generally located on property that we have the right to use under leases, easements, rights-of-way, permits and licenses. We believe that we generally have satisfactory title to the properties that we own and use in our business, subject to liens, restrictions, easements and other encumbrances that do not materially either detract from the value of our assets or interfere with the operation of our business.

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Record title to some of our property may reflect names of prior owners until we have made the appropriate filings in the jurisdictions in which such assets are located. Title to some of our assets may be subject to encumbrances. Substantially all of our pipelines are constructed on rights-of-way granted by the apparent owners of record of the properties. Lands over which pipeline rights-of-way have been obtained may be subject to prior liens that have not been subordinated to the rights-of-way grants. In some cases, not all of the apparent record owners have joined in the right-of-way grants, but in substantially all such cases the signatures of the majority of apparent record owners have been obtained. Permits for our pipelines have been obtained from public authorities to cross over or under, or to lay facilities along, water courses, county roads, municipal streets and state highways, and in some instances such permits are revocable at the election of the grantor, or we may be required to relocate the pipeline at our own expense.

Our principal executive offices are located at One Leadership Square, 211 North Robinson Avenue, Suite 150, Oklahoma City, Oklahoma 73102; our telephone number is 405-525-7788. We currently occupy 162,053 square feet of office space at our principal executive offices under a lease that expires June 30, 2019. Although we may require additional office space as our business expands, we believe that our current facilities are adequate to meet our needs for the immediate future.

Item 3. Legal Proceedings

In the normal course of business, we are confronted with issues or events that may result in a contingent liability. These generally relate to lawsuits or claims made by third parties, including governmental agencies. When appropriate, management consults with legal counsel and other appropriate experts to assess the claim. If, in management’s opinion, we have incurred a probable loss as set forth by GAAP, an estimate is made of the loss and the appropriate accounting entries are reflected in our Consolidated Financial Statements. At the present time, based on currently available information, management believes that any reasonably possible losses in excess of accrued amounts arising out of pending or threatened lawsuits or claims would not be quantitatively material to our financial statements and would not have a material adverse effect on our consolidated financial position, results of operations or cash flows.

Item 4. Mine Safety Disclosures

Not applicable.

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Part II

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

Market Information

Our common units are listed on the NYSE under the symbol "ENBL." The following table sets forth the high and low closing prices of the common units as well as the amount of cash distributions declared and paid on the common units for the years ended December 31, 2016 and 2015.

	Common Units		
	High	Low	Distribution per common unit
Year ended December 31, 2016			
Fourth Quarter	$16.54	$14.33	$ 0.318
Third Quarter	16.03	12.39	0.318
Second Quarter	16.16	7.72	0.318
First Quarter	8.94	5.52	0.318
Year ended December 31, 2015			
Fourth Quarter	$13.97	$6.60	$ 0.318
Third Quarter	16.46	11.74	0.318
Second Quarter	17.80	15.98	0.316
First Quarter	19.75	16.19	0.3125

On February 10, 2017, the Board of Directors declared a quarterly distribution of $0.318 per common unit, which will be paid on February 28, 2017, to unitholders of record at the close of business on February 21, 2017. The last reported sale price of our common units on the NYSE on February 1, 2017 was $16.21. As of February 1, 2017, there were 224,532,959 common units outstanding and approximately 14 unitholders of record of our common units. This number does not include unitholders whose units are held in trust by other entities. The actual number of unitholders is greater than the number of holders of record. We have also issued 207,855,430 subordinated units and ownership interests in the general partner, for which there is no established public trading market. All of the subordinated units and general partner interests are held by affiliates of our general partner.

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 (defined below) to unitholders of record on the applicable record date.

Definition of Available Cash

Available cash is defined in our partnership agreement, which is an exhibit to this Annual Report on Form 10-K. Available cash generally means, for any quarter, all cash and cash equivalents on hand at the end of that quarter:

- less, the amount of cash reserves established by our general partner to:

- provide for the proper conduct of our business (including cash reserves for our future capital expenditures, future acquisitions and anticipated future debt service requirements and refunds of collected rates reasonably likely to be refunded as a result of a settlement or hearing related to FERC rate proceedings or rate proceedings under applicable law subsequent to that quarter);
- comply with applicable law, any of our debt instruments or other agreements;
- provide funds for distributions to our unitholders and to our general partner for any one or more of the next four quarters (provided that our general partner may not establish cash reserves for distributions if the effect of the establishment of such reserves will prevent us from distributing the minimum quarterly distribution on all

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common units and any cumulative arrearages on such common units for the current quarter); or

- provide funds for distributions on our preferred units;
- plus, if our general partner so determines, all or any portion of the cash on hand on the date of determination of available cash for the quarter resulting from working capital borrowings made subsequent to the end of such quarter.

Minimum Quarterly Distribution

The Minimum Quarterly Distribution, as set forth in the Partnership Agreement, is $0.2875 per unit per quarter, or $1.15 per unit on an annualized basis to the extent we have sufficient cash from our operations after the establishment of cash reserves and the payment of costs and expenses, including reimbursements of expenses to our general partner. Our current quarterly distribution is $0.318 per unit, or $1.272 per unit annualized. However, there is no guarantee that we will pay the minimum quarterly distribution on our units in any quarter. Even if our cash distribution policy is not modified or revoked, the amount of distributions paid under our policy and the decision to make any distribution is determined by our general partner, taking into consideration the terms of our partnership agreement. Please read Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources" for a discussion of the restrictions included in our credit agreement that may restrict our ability to make distributions.

General Partner Interest and Incentive Distribution Rights

Enable GP owns a non-economic general partner interest in the Partnership and thus will not be entitled to distributions that the Partnership makes prior to the liquidation of the Partnership in respect of such general partner interest. Enable GP currently holds incentive distribution rights that entitle it to receive increasing percentages, up to a maximum of 50.0%, of the cash the Partnership distributes from operating surplus (as defined in the Partnership Agreement) in excess of $0.330625 per unit per quarter. The maximum distribution of 50.0% does not include any distributions that Enable GP or its affiliates may receive on common units or subordinated units that they own. Please read Note 5 of the Notes to Consolidated Financial Statements in Item 8. "Financial Statements and Supplementary Data" for additional information.

Percentage Allocations of Available Cash from Operating Surplus

The following table illustrates the percentage allocations of available cash from operating surplus between the unitholders and our general partner (through the incentive distribution rights) based on the specified target distribution levels. The amounts set forth under "Marginal Percentage Interest in Distributions" are the percentage interests of our general partner and the unitholders in any available cash from operating surplus we distribute up to and including the corresponding amount in the column "Total Quarterly Distribution Per Unit Target Amount." The percentage interests shown for our unitholders for the minimum quarterly distribution are also applicable to quarterly distribution amounts that are less than the minimum quarterly distribution. The percentage interests set forth below for our general partner assume that our general partner has not transferred its incentive distribution rights and that there are no arrearages on common units.

	Total Quarterly Distribution Per Unit Target Amount	Marginal Percentage Interest in Distributions	
		Unitholders	General Partner
Minimum Quarterly Distribution	$0.2875	100.0 %	— %
First Target Distribution	up to $0.330625	100.0 %	— %
Second Target Distribution	above $0.330625 up to $0.359375	85.0 %	15.0 %
Third Target Distribution	above $0.359375 up to $0.431250	75.0 %	25.0 %
Thereafter	above $0.431250	50.0 %	50.0 %

Subordinated Units

General

As of December 31, 2016, all subordinated units are held by CenterPoint Energy and OGE Energy. These units are considered subordinated because for a period of time, defined by the Partnership Agreement as the subordination period, the subordinated units will not be entitled to receive any distributions until the common units have received distributions of available cash each quarter from operating surplus in an amount equal to the minimum quarterly distribution plus any arrearages on minimum quarterly distributions on the common units from prior quarters. In addition, the subordinated units are not entitled to arrearages on minimum

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quarterly distributions. On the expiration of the subordination period, the subordinated units will convert to common units on a one-for-one basis.

Subordination Period

The subordination period began on the closing date of the IPO and expires on the first to occur of the following dates: (1) the first business day following the distribution of available cash in respect of any quarter beginning with the quarter ending June 30, 2017 that the following tests are met: (a) distributions of available cash from operating surplus on each of the outstanding common units and subordinated units equal or exceed $1.15 per unit (the annualized minimum quarterly distribution) for each of the three consecutive, non-overlapping four-quarter periods immediately preceding that date; (b) the adjusted operating surplus generated during each of the three consecutive, non-overlapping four-quarter periods immediately preceding that date equaled or exceeded the sum $1.15 (the annualized minimum quarterly distribution) on all of the common units and subordinated units outstanding during those periods on a fully diluted weighted average basis; and (c) there are no arrearages in the payment of the minimum quarterly distributions on the common units or (2) the first business day following the distribution of available cash in respect of any quarter beginning with the quarter ending June 30, 2015 that the following tests are met: (a) distributions of available cash from operating surplus on each of the outstanding common units and subordinated units equal to or exceeding $1.725 per unit (150% of the annualized minimum quarterly distribution) for the four consecutive quarter period immediately preceding that date; (b) the adjusted operating surplus generated during the four consecutive quarter period immediately preceding that date equaled or exceed $1.725 per unit (150% of the annualized minimum quarterly distribution) on all of the common units and subordinated units outstanding during that period on a fully diluted weighted average basis plus the corresponding incentive distribution rights; and (c) there are no arrearages in the payment of the minimum quarterly distributions on the common units.

Equity Compensation Plans

The information relating to our equity compensation plans required by Item 5 is incorporated by reference to such information as set forth in Item 12. “Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters” contained herein.

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Item 6. Selected Financial Data

The following tables set forth, for the periods and as of the dates indicated, the selected historical financial and operating data of Enable Midstream Partners, LP, which is derived from the historical books and records of the Partnership. On May 1, 2013 (formation), OGE Energy and ArcLight indirectly contributed 100% of the equity interests in Enogex to the Partnership in exchange for common units and, for OGE Energy only, interests in our general partner. The transaction was considered a business combination for accounting purposes, with the Partnership considered the acquirer of Enogex. Subsequent to May 1, 2013, the financial and operating data of the Partnership are consolidated to reflect the acquisition of Enogex and the retention of certain assets and liabilities by CenterPoint Energy.

	Year Ended December 31,				
	2016	2015	2014	2013	2012
	(In millions, except for per unit data)				
Results of Operations Data:					
Revenues	$2,272	$2,418	$3,367	$2,489	$952
Cost of natural gas and natural gas liquids, excluding depreciation and amortization	1,017	1,097	1,914	1,313	129
Operation and maintenance, General and administrative	465	522	527	429	267
Depreciation and amortization	338	318	276	212	106
Impairments	9	1,134	8	12	—
Taxes other than income	58	59	56	54	34
Operating income (loss)	385	(712)	586	469	416
Interest expense	(99)	(90)	(70)	(67)	(85)
Equity in earnings of equity method affiliates	28	29	20	15	31
Interest income—affiliated companies	—	—	—	9	21
Step acquisition gain	—	—	—	—	136
Other, net	—	2	(1)	—	—
Income (loss) before income taxes	314	(771)	535	426	519
Income tax expense (benefit)	1	—	2	(1,192)	203
Net income (loss)	$313	$(771)	$533	$1,618	$316
Less: Net income (loss) attributable to noncontrolling interest	1	(19)	3	3	—
Net income (loss) attributable to limited partners	$312	$(752)	$530	$1,615	$316
Less: Series A Preferred Unit distributions	22	—	—	—	
Net income (loss) attributable to common and subordinated units(1)	$290	$(752)	$530	$289	
Basic and diluted (loss) earnings per common limited partner unit(1)(2)	$0.69	$(1.78)	$1.29	$0.74	
Basic and diluted (loss) earnings per subordinated limited partner unit(3)	$0.68	$(1.78)	$1.28		
Distributions declared per unit(4)			$0.4534	$0.6086	
Distributions declared per unit(5)	$1.2720	$1.2645	$0.8577		
Balance Sheet Data (at period end):					
Property, plant and equipment, net	$10,143	$10,131	$9,582	$8,990	$4,705
Total assets	11,212	11,226	11,837	11,232	6,482
Long-term debt, including current portion	2,993	3,270	2,544	2,483	1,762
Partners' Equity	7,794	7,531	8,823	8,181	3,221

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	Year Ended December 31,				
	2016	2015	2014	2013	2012
	(In millions, except for operating data)				
Cash Flow Data:					
Net cash flows provided by (used in):					
Operating activities	$721	$726	$769	$648	$451
Investing activities	(367)	(946)	(815)	(140)	(645)
Financing activities	(335)	212	(50)	(400)	194
Other Financial Data [6]:					
Gross margin	$1,255	$1,321	$1,453	$1,176	$823
Adjusted EBITDA	873	801	881	729	561
DCF[7]	639	538	634	494	
Operating Data:					
Gathered volumes—TBtu	1,143	1,148	1,221	1,113	874
Gathered volumes—TBtu/d	3.13	3.14	3.34	3.05	2.39
Natural gas processed volumes—TBtu	658	651	569	397	73
Natural gas processed volumes—TBtu/d	1.80	1.78	1.56	1.09	0.20
NGLs produced—MBbl/d[8]	78.70	73.55	66.74	44.51	—
NGLs sold—MBbl/d[8][9]	78.16	75.55	68.67	44.91	0.25
Condensate sold—MBbl/d	5.27	5.13	4.38	1.88	—
Crude Oil - Gathered volumes—MBbl/d[10]	25.00	13.86	3.64	—	—
Transported volumes—TBtu	1,788	1,814	1,808	1,608	1,378
Transportation volumes—TBtu/d	4.88	4.97	4.95	4.41	3.76
Interstate firm contracted capacity—Bcf/d	7.04	7.19	7.73	8.01	7.94
Intrastate average deliveries—TBtu/d	1.72	1.84	1.61	1.58	—

(1) Net income (loss) attributable to common and subordinated units and basic and diluted earnings per unit reflect net income (loss) attributable to Enable Midstream Partners, LP subsequent to its formation as a limited partnership on May 1, 2013, as no limited partner units were outstanding prior to this date.

(2) Historical basic and diluted earnings per common limited partner unit reflects the 1 for 1.279082616 reverse unit split effected on March 25, 2014.

(3) Basic and diluted earnings per subordinated unit reflect net income (loss) attributable to the Partnership for periods subsequent to its IPO, as no subordinated units were outstanding prior to this date.

(4) Distributions attributable to periods prior to the IPO are in accordance with the First Amended and Restated Agreement of Limited Partnership. Distributions declared per unit prior to the IPO relate to common units, as no subordinated units were outstanding prior to the date of the IPO.

(5) Distributions attributable to periods subsequent to the IPO are in accordance with the Partnership Agreement. Distributions declared per unit relate to common and subordinated units.

(6) See “Reconciliation of Non-GAAP Financial Measures” in Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operations” for a reconciliation of Gross margin, Adjusted EBITDA and DCF to their most directly comparable financial measure calculated and presented in accordance with GAAP.

(7) DCF attributable to periods in years prior to the year of our formation are not shown.

(8) Excludes condensate.

(9) NGLs sold includes volumes of NGLs withdrawn from inventory or purchased for system balancing purposes.

(10) Initial operation of our crude oil gathering system began on November 1, 2013.

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

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with our consolidated financial statements and notes included in this report.

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Overview

We are a Delaware limited partnership formed in May 2013 to own, operate and develop strategically located midstream assets. We completed our IPO in April 2014, and we are traded on the NYSE under the symbol “ENBL.” We were formed by CenterPoint Energy, OGE Energy and ArcLight. Our general partner is owned by CenterPoint Energy and OGE Energy.

Our Operations

Our assets and operations are organized into two reportable segments: (i) gathering and processing and (ii) transportation and storage. Our gathering and processing segment primarily provides natural gas and crude oil gathering and natural gas processing services to our producer customers. Our transportation and storage segment provides interstate and intrastate natural gas pipeline transportation and storage services primarily to our producer, power plant, LDC and industrial end-user customers.

Our gathering and processing assets include approximately 12,600 miles of natural gas gathering pipelines, 14 natural gas processing plants with approximately 2.5 Bcf/d of processing capacity and approximately 992,000 horsepower of compression as of December 31, 2016 in the Anadarko, Arkoma and Ark-La-Tex Basins. In addition, our gathering and processing assets include approximately 175 miles of crude oil gathering pipelines and 160 miles of produced water gathering pipelines serving the Bakken Shale in the Williston Basin.

Our transportation and storage assets include approximately 9,990 miles of natural gas intrastate and interstate transportation pipelines across nine states, eight natural gas storage facilities with approximately 85.0 Bcf of storage capacity and approximately 824,500 horsepower of compression. As part of these transportation and storage assets, we own a 50% interest in, and provide field operations for, SESH, an approximately 290-mile interstate pipeline providing access to the Southeast power generation market.

Items Affecting the Comparability of Our Financial Results

The comparability of our current financial condition and results of operations with our historical financial conditions and results of operations may be affected by the items described below.

Capitalization

In April 2014, the Partnership completed its IPO of 25,000,000 units and received net proceeds of $464 million. The Partnership retained the net proceeds of the offering for general partnership purposes, including proceeds to fund expansion capital expenditures and to pre-fund demand fees expected to be incurred over the next three years relating to certain expiring transportation and storage contracts.

On February 18, 2016, the Partnership completed the private placement of 14,520,000 Series A Preferred Units for a cash purchase price of $25.00 per Series A Preferred Unit, resulting in proceeds of $362 million, net of issuance costs. The Partnership incurred approximately $1 million of expenses related to the offering, which is accounted for as an offset to the proceeds. In connection with the closing of the private placement, the Partnership redeemed approximately $363 million of notes scheduled to mature in 2017 payable to a wholly-owned subsidiary of CenterPoint Energy. In connection with the private placement, Enable GP adopted the Partnership’s Third Amended and Restated Agreement of Limited Partnership on February 18, 2016, which, among other things, authorized the issuance of Series A Preferred Units. The Series A Preferred Units rank senior to the Partnership’s common units with respect to the payment of distributions and the distribution of assets upon liquidation, dissolution and winding up; have no stated maturity, are not subject to any sinking fund and will remain outstanding indefinitely unless repurchased or redeemed by the Partnership or converted into its common units in connection with a change of control; receive on a non-cumulative basis if and when declared by the general partner, a quarterly cash distribution, subject to certain adjustments, equal to an annual rate of 10% on the stated liquidation preference from the date of original issue to, but not including, the five year anniversary of the original issue date and an annual rate of LIBOR plus 850 bps on the stated liquidation preference thereafter.

On November 29, 2016, the Partnership closed a public offering of 10,000,000 common units at a price to the public of $14.00 per common unit. In connection with the offering, the Partnership, the underwriters and an affiliate of ArcLight entered into an underwriting agreement that provided an option for the underwriters to purchase up to an additional 1,500,000 common units, with 75,719 common units to be sold by the Partnership and 1,424,281 to be sold by the affiliate of ArcLight. The underwriters exercised the option to purchase all of the additional common units, and the Partnership received proceeds (net of underwriting

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discounts, structuring fees and offering expenses) of $137 million from the offering. Please read "—Liquidity and Capital Resources".

Financing

In January 2014, the Partnership initiated our $1.4 billion commercial paper program. This program is used for general corporate purposes. Commercial paper issuances effectively reduce our borrowing capacity under our current Revolving Credit Facility. The Partnership’s ability to access the commercial paper market is dependent on its credit rating. On February 2, 2016, Standard & Poor’s Ratings Services lowered both the credit rating and the short-term rating of the Partnership from an investment grade to a non-investment grade rating. As a result, we expect our access to the commercial paper program to be limited unless these ratings improve.

On May 27, 2014, the Partnership completed the private offering of 2019 Notes, 2024 Notes and 2044 Notes, with registration rights. The Partnership received aggregate proceeds of $1.63 billion. Certain of the proceeds were used to repay the 2013 Term Loan Agreement, the EOIT $250 million variable rate term loan, the EOIT $200 million 6.875% senior notes due July 15, 2014 and for general corporate purposes. See Note 10 for discussion of the repayment of the EOIT $200 million 6.875% senior notes. A wholly owned subsidiary of CenterPoint Energy guaranteed collection of the Partnership’s obligations under the 2019 Notes and 2024 Notes, which expired on May 1, 2016.

On June 18, 2015, the Partnership amended and restated its Revolving Credit Facility to, among other things, increase the borrowing capacity thereunder to $1.75 billion and extend its maturity date to June 18, 2020. On July 31, 2015, the Partnership entered into a term loan agreement providing for an unsecured, three-year $450 million term loan agreement (2015 Term Loan Agreement). Please read “—Liquidity and Capital Resources.”

Trends and Outlook

We expect our business to continue to be impacted by the trends affecting our industry that are discussed below. Our outlook is based on assumptions regarding the impact of these trends that we have developed by interpreting the information currently available to us. If our assumptions or interpretation of available information prove to be incorrect, our future financial condition and results of operations may differ materially from our expectations.

Commodity Price Environment

Our business is impacted by commodity prices which have declined and otherwise experienced significant volatility in recent years. In early 2016, natural gas and crude oil prices dropped to their lowest levels in over 10 years. Both natural gas and crude oil prices increased moderately in the second half of 2016. If current commodity prices levels persist, or if commodity price levels decline, our future volumes and cash flows may be negatively impacted.

Commodity prices impact the drilling and production of natural gas and crude oil in the areas served by our systems, and the volumes on our systems are negatively impacted if producers decrease drilling and production in those areas served. Both our gathering and processing segment and our transportation and storage segment can be impacted by drilling and production. Our gathering and processing segment primarily serve producers, and many producers utilize the services provided by our transportation and storage segment. A decrease in volumes will decrease the cash flows from our systems. In addition, our processing arrangements expose us to commodity price fluctuations. For more information regarding the impact of commodity prices, drilling and production on the volumes on our systems as well as our exposure to commodity prices under our processing arrangements, see Part I, Item 1A. “Risk Factors—Risks Related to Our Business.”

We have attempted to mitigate the impact of commodity prices on our business by entering into hedges, focusing on contracting fee-based business and converting existing commodity-based contracts to fee-based contracts. For additional information regarding our commodity price risk, see Item 7A. “Quantitative and Qualitative Disclosures About Market Risk—Commodity Price Risk.”

Commodity Supply and Demand Dynamics

Despite recent low commodity prices, our long-term view is that natural gas and crude oil production in the U.S. will increase. Over the past several years, there has been a fundamental shift in U.S. natural gas and crude oil production towards tight gas formations and shale plays. Advancements in technology have allowed producers to efficiently extract natural gas and crude oil from these formations and plays. As a result, the proven reserves of natural gas and crude oil in the United States have significantly increased and the price of natural gas and crude oil has decreased compared to historical periods.

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Natural gas continues to be a critical component of energy demand in the United States. Over the long term, management believes that the prospects for continued natural gas demand are favorable and will be driven by population and economic growth, as well as the continued displacement of coal-fired power plants by natural gas-fired power plants due to the price of natural gas and stricter government environmental regulations on the mining and burning of coal. The EIA projects that the majority of domestic consumption growth will be in the electric power, industrial and liquefaction for export sectors where the aggregate natural gas demand of these sectors is expected to grow from approximately 17.8 Tcf in 2016 to approximately 21.0 Tcf in 2040. We believe that increasing consumption of natural gas over the long term in these sectors will continue to drive demand for our natural gas gathering, processing, transportation and storage services.

Capital Market Volatility

We may access the capital markets to fund our expansion capital expenditures. Historically, unit prices of midstream master limited partnerships have experienced periods of volatility. In addition, because our common units are yield-based securities, rising market interest rates could impact the relative attractiveness of our common units to investors. Further, fluctuations in energy and commodity prices can create volatility in our common unit prices, which could impact investor appetite for our common units. Volatility in energy and commodity prices, as well as other macro-economic factors could impact the relative attractiveness of our debt securities to investors. As a result of capital market volatility, we may be unable to issue equity securities or debt on satisfactory terms, or at all, which may limit our ability to expand our operations or make future acquisitions. See Part I, Item 1A. “Risk Factors—Risks Related to Our Business.”

Regulatory Compliance

The regulation of gathering and transmission pipelines, storage and related facilities by FERC and other federal and state regulatory agencies, including the DOT, has a significant impact on our business. For example, the DOT’s Pipeline and Hazardous Materials Safety Administration, or PHMSA, has established pipeline integrity management programs that require more frequent inspections of pipeline facilities and other preventative measures, which may increase our compliance costs and increase the time it takes to obtain required permits. Additionally, increased regulation of oil and natural gas producers, including regulation associated with hydraulic fracturing, could reduce regional supply of oil and natural gas and therefore throughput on our gathering systems. For more information, see Item 1. “Business—Rate and Other Regulation.”

Customer Concentration

We rely on certain key natural gas producer customers for a significant portion of our natural gas and NGLs supply. For the year ended December 31, 2016, our top ten natural gas producer customers accounted for approximately 66% of our gathered volumes. These customers include affiliates of Continental, Vine, GeoSouthern, XTO, Apache, Tapstone, Chesapeake, BP, Covey Park and Marathon. See Item 1A. “Risk Factors—Risks Related to Our Business.”

We rely on certain key utilities and producers for a significant portion of our transportation and storage demand. For the year ended December 31, 2016, our top transportation and storage customers by revenue were affiliates of CenterPoint Energy, Spire, XTO, AEP, OGE Energy, Continental, Chesapeake, MEP, EOG and Entergy. See Part I, Item 1A. “Risk Factors—Risks Related to Our Business.”

Credit Risk

We are exposed to certain credit risks relating to our ongoing business operations. Credit risk includes the risk that counterparties that owe us money or energy will breach their obligations. If the counterparties to these arrangements fail to perform, we may be forced to enter into alternative arrangements. In that event, our financial results could be adversely affected, and we could incur losses. We examine the creditworthiness of third party customers to whom we extend credit and manage our exposure to credit risk through credit analysis, credit approval, credit limits and monitoring procedures, and for certain transactions, we may request letters of credit, prepayments or guarantees, or seek to renegotiate our contract to reduce credit exposure.

Measures We Use to Evaluate Results of Operations

We use a variety of operational and financial measures to evaluate our results of operations and our financial condition and to manage our business. The measures that we use to analyze our business include: (i) throughput volumes, (ii) operation and maintenance and general and administrative expenses, (iii) Gross margin, (iv) Adjusted EBITDA, (v) Adjusted interest expense, (vi) DCF and (vii) Distribution coverage ratio.

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Throughput Volumes

Throughput volume is operating data. The volume of natural gas that we gather, process, transport and store depends significantly on the level of production from natural gas wells connected to our systems. Gathering and processing as well as transportation and storage can be impacted by drilling and production because the customers for our gathering and processing services are primarily producers, and many producers utilize our transportation and storage services. Aggregate production volumes are impacted by the overall amount of drilling and completion activity, as production must be maintained or increased by new drilling or other activity, because the production rate of a well declines over time. Producers' willingness to engage in new drilling is determined by a number of factors, which include: the prevailing and projected prices of natural gas, NGLs and crude oil; the cost to drill and operate a well; the availability and cost of capital; technological advances in drilling and production techniques; and environmental and other government regulations. We generally expect the level of drilling to positively correlate with long-term trends in commodity prices. Similarly, we generally expect the level of production to positively correlate with drilling activity.

To maintain and increase throughput volumes on our gathering and processing systems, we must compete to connect to new wells as production from existing wells declines. We actively monitor drilling activity in the areas served by our gathering and processing systems to pursue new customers and new wells. To maintain and increase the throughput volumes on our transportation and storage systems, we must compete for the business of producers and other customers who have existing and new sources of supply in the areas served by our systems, and we must compete for the business of power plants, LDCs, industrial end users and other customers who have existing and new sources of demand in the areas served by our systems.

We actively monitor customer activity in the areas we serve to pursue new supply and demand opportunities. In both gathering and processing and transportation and storage, we compete for customers based on service offerings, operating flexibility, receipt and delivery points, available capacity and price.

Operation and Maintenance and General and Administrative Expenses

Operation and Maintenance and General and Administrative Expenses is a GAAP financial measure. We seek to maximize the profitability of our operations by effectively managing operation and maintenance and general and administrative expenses. These expenses are comprised primarily of labor expenses, lease costs, utility costs, insurance premiums, repair expenses and maintenance expenses. These labor expenses, lease costs, utility costs and insurance premiums have remained relatively stable across periods in the current low inflation environment, but repair and maintenance expense can fluctuate from period to period based on the activities performed and the timing of expenses. The level of drilling activity impacts competition for personnel, supplies and equipment. Increased competition could place upward pressure on the cost of labor, supplies and miscellaneous equipment.

Use of Non-GAAP Financial Measures

Gross margin, Adjusted EBITDA, Adjusted interest expense, DCF and Distribution coverage ratio are not financial measures presented in accordance with GAAP. These financial measures are subject to adjustments that have the effect of excluding amounts that are included in the most directly comparable measure calculated and presented in accordance with GAAP. Because these non-GAAP financial measures exclude amounts that are included in the most directly comparable GAAP financial measures, they have important limitations as an analytical tool. We nevertheless believe that the presentation of these non-GAAP financial measures provides useful information to investors regarding our financial condition and results of operations because they are the financial measures used by management to evaluate and manage our business.

We have provided definitions for Gross margin, Adjusted EBITDA, Adjusted interest expense, DCF and Distribution coverage ratio. Although the use of non-GAAP financial measures with the same or similar titles is common in our industry, comparability may vary from one company to another. Because Gross margin, Adjusted EBITDA, Adjusted interest expense, DCF and Distribution coverage ratio may be defined differently by other companies in our industry, our presentation of these non-GAAP financial measures may not be directly comparable to non-GAAP financial measures of other companies with the same or similar titles.

Gross margin is most directly comparable to the GAAP financial measure revenue. When used as a financial measure, Adjusted EBITDA is most directly comparable to the GAAP financial measure net income attributable limited partners. When used as a liquidity measure, Adjusted EBITDA is most directly comparable to the GAAP liquidity measure net cash provided by operating activities. Adjusted interest expense is most directly comparable to the GAAP financial measure interest expense. DCF is most directly comparable to the GAAP financial measure net income attributable to limited partners. Distribution coverage ratio is computing utilizing DCF, which is most directly comparable to the GAAP financial measure net income attributable to limited partners. These non-GAAP financial measures should not be considered a substitute for the most directly comparable financial

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measures. Reconciliations of these non-GAAP financial measures to their most directly comparable GAAP financial measures are provided in "—Reconciliation of non-GAAP Financial Measures" below.

Gross Margin

We define gross margin as total revenues minus costs of natural gas and natural gas liquids, excluding depreciation and amortization. Total revenues consist of the fees that we charge our customers and the sales price of natural gas and natural liquids that we sell. The cost of natural gas and natural gas liquids consists of the purchase price of natural gas and natural gas liquids that we purchase. We deduct the cost of natural gas and natural gas liquids from total revenue to arrive at a measure of the core profitability of our mix of fee-based and commodity-based customer arrangements. We use gross margin as a performance measure to analyze the core profitability of our customer arrangements. Please read "—Results of Operations" and "—Non-GAAP Financial Measures."

The following table shows the components of our gross margin for the year ended December 31, 2016.

	Fee-Based Demand/ Commitment/ Guaranteed Return	Fee-Based Volume Dependent	Commodity-Based	Total
Year Ended December 31, 2016				
Gathering and Processing Segment	34 %	44 %	22 %	100 %
Transportation and Storage Segment	93 %	5 %	2 %	100 %
Partnership Weighted Average	59 %	28 %	13 %	100 %

Adjusted EBITDA

We define Adjusted EBITDA as net income (loss) attributable to limited partners plus depreciation and amortization expense, interest expense, income tax expense, distributions received from equity method affiliate, non-cash equity based compensation, impairments and certain other non-cash losses (including decreases in the fair value of derivatives, lower of cost or net realizable value adjustments, losses on sales of assets and write-downs of materials and supplies), less equity in earnings of equity method affiliate, noncontrolling interest share of Adjusted EBITDA and certain other non-cash gains (including increases in the fair value of derivatives and lower of the cost or net realizable value adjustment recoveries upon the sale of the related inventory). We use Adjusted EBITDA to evaluate our operating profitability unburdened by our capital structure. Because Adjusted EBITDA adds back to net income the non-cash accounting charges of depreciation and amortization and disregards interest paid on debt financing and income taxes on earnings, we believe that it is useful for measuring our operating cash flow. However, Adjusted EBITDA does not measure, and should not be confused with, our actual cash flow which accounts for interest paid on debt financing, income taxes and other cash charges.

Adjusted Interest Expense

We define adjusted interest expense as interest expense plus amortization of premium on long-term debt and capitalized interest, less amortization of debt costs. We use adjusted interest expense to assess the Partnership's ability to incur and service debt and fund capital expenditures.

DCF

We define DCF as Adjusted EBITDA, as further adjusted for Series A Preferred Unit distributions, Adjusted interest expense, maintenance capital expenditures and current income taxes. We use DCF as a proxy for measuring cash available for distributions. However, DCF does not reflect the cash reserves set aside for our operations by our Board of Directors prior to determining the amount of our distributions to our limited partners, and should not be confused with our actual cash available for distribution. For more information on the determination of our distributions by our Board of Directors see "Liquidity and Capital Resources—Distributions" below.

Distribution Coverage Ratio

We define Distribution coverage ratio as DCF divided by distributions related to common and subordinated unitholders. DCF is most directly comparable to net income attributable to limited partners, which is reconciled below. We use Distribution coverage ratio to assess the ability of the Partnership's assets to generate sufficient cash flow to make distributions to its partners.

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Results of Operations

The following tables summarizes the composition of our results of operations for the years ended December 31, 2016, 2015 and 2014.

December 31, 2016	Gathering and Processing	Transportation and Storage	Eliminations	Enable Midstream Partners, LP
	(In millions)			
Product sales	$1,081	$ 479	$ (388)	$ 1,172
Service revenue	559	545	(4)	1,100
Total Revenues	1,640	1,024	(392)	2,272
Cost of natural gas and natural gas liquids (excluding depreciation and amortization shown separately)	915	492	(390)	1,017
Gross margin(1)	725	532	(2)	1,255
Operation and maintenance, General and administrative	276	191	(2)	465
Depreciation and amortization	212	126	—	338
Impairments	9	—	—	9
Taxes other than income tax	32	26	—	58
Operating income	$196	$ 189	$ —	$ 385
Equity in earnings of equity method affiliate	$—	$ 28	$ —	$ 28

December 31, 2015	Gathering and Processing	Transportation and Storage	Eliminations	Enable Midstream Partners, LP
	(In millions)			
Product sales	$1,118	$ 590	$ (374)	$ 1,334
Service revenue	545	542	(3)	1,084
Total Revenues	1,663	1,132	(377)	2,418
Cost of natural gas and natural gas liquids (excluding depreciation and amortization shown separately)	908	565	(376)	1,097
Gross margin(1)	755	567	(1)	1,321
Operation and maintenance, General and administrative	293	230	(1)	522
Depreciation and amortization	195	123	—	318
Impairments	543	591	—	1,134
Taxes other than income tax	30	29	—	59
Operating loss	$(306)	$ (406)	$ —	$ (712)
Equity in earnings of equity method affiliate	$—	$ 29	$ —	$ 29

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December 31, 2014	Gathering and Processing	Transportation and Storage	Eliminations	Enable Midstream Partners, LP
	(In millions)			
Product sales	$1,907	$ 1,009	$ (616)	$ 2,300
Service revenue	517	568	(18)	1,067
Total Revenues	2,424	1,577	(634)	3,367
Cost of natural gas and natural gas liquids (excluding depreciation and amortization shown separately)	1,585	961	(632)	1,914
Gross margin[1]	839	616	(2)	1,453
Operation and maintenance, General and administrative	297	232	(2)	527
Depreciation and amortization	160	116	—	276
Impairments	8	—	—	8
Taxes other than income tax	25	31	—	56
Operating income	$349	$ 237	$ —	$ 586
Equity in earnings of equity method affiliate	$—	$ 20	$ —	$ 20

(1) Gross margin is a non-GAAP measure and is defined and reconciled to its most directly comparable financial measures calculated and presented below under the caption Reconciliations of Non-GAAP Financial Measures.

	Year Ended December 31,		
	2016	2015	2014
Operating Data:			
Gathered volumes—TBtu	1,143	1,148	1,221
Gathered volumes—TBtu/d	3.13	3.14	3.34
Natural gas processed volumes—TBtu	658	651	569
Natural gas processed volumes—TBtu/d	1.80	1.78	1.56
NGLs produced—MBbl/d[1]	78.70	73.55	66.74
NGLs sold—MBbl/d[1][2]	78.16	75.55	68.67
Condensate sold—MBbl/d	5.27	5.13	4.38
Crude Oil—Gathered volumes—MBbl/d	25.00	13.86	3.64
Transported volumes—TBtu	1,788	1,814	1,808
Transportation volumes—TBtu/d	4.88	4.97	4.95
Interstate firm contracted capacity—Bcf/d	7.04	7.19	7.73
Intrastate average deliveries—TBtu/d	1.72	1.84	1.61

	Year Ended December 31,		
	2016	2015	2014
Operating Data By Basin:			
Anadarko			
Gathered volumes—TBtu/d	1.65	1.59	1.38
Natural gas processed volumes—TBtu/d	1.47	1.38	1.12
NGLs produced—MBbl/d[1]	65.19	58.51	51.56
Arkoma			
Gathered volumes—TBtu/d	0.62	0.67	0.77
Natural gas processed volumes—TBtu/d	0.10	0.10	0.10
NGLs produced—MBbl/d[1]	4.86	4.97	4.41

Ark-La-Tex			
Gathered volumes—TBtu/d	0.86	0.88	1.19
Natural gas processed volumes—TBtu/d	0.23	0.30	0.34
NGLs produced—MBbl/d [(1)]	8.65	10.07	10.77

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(1) Excludes condensate.
(2) NGLs sold includes volumes of NGLs withdrawn from inventory or purchased for system balancing purposes.

Gathering and Processing

2016 compared to 2015. Our gathering and processing segment reported operating income of $196 million for 2016 compared to an operating loss of $306 million for 2015. The difference of $502 million in operating income between periods was primarily due to $543 million of impairments recognized in 2015 related to goodwill and long-lived assets, as compared to $9 million of impairments recognized in 2016 related to long-lived assets, and a $17 million decrease in operation and maintenance and general and administrative expenses. These increases were partially offset by a $30 million decrease in gross margin, a $17 million increase in depreciation and amortization and a $2 million increase in taxes other than income tax in 2016.

Our gathering and processing segment revenues decreased by $23 million in 2016. The decrease was primarily due to a $43 million reduction in revenues from sales of natural gas as a result of lower average natural gas prices and volumes sold, a $33 million reduction in revenues from changes in the fair value of condensate and NGL derivatives, a $12 million decrease in one-time project reimbursements and a $4 million decrease in third party measurement and communication services. These decreases were partially offset by a $46 million increase in revenues from sales of NGLs as a result of higher volumes sold, a $13 million increase in crude oil gathering revenue due to higher gathered volumes in the Williston Basin and an $11 million increase in natural gas gathering revenue as a result of increased billings under minimum volume commitments and higher fees and gathered volumes in the Anadarko Basin.

Our gathering and processing segment gross margin decreased by $30 million in 2016. The decrease was primarily due to a $33 million reduction in gross margin from changes in the fair value of condensate and NGL derivatives, a $14 million decrease in natural gas sales due to lower average natural gas prices and a $4 million decrease in third party measurement and communication services. Additionally, there was a $12 million decrease in one-time project reimbursements. These decreases were partially offset by a $13 million increase in crude oil gathering margin due to higher gathered volumes in the Williston Basin, an $11 million increase in gross margin from natural gas gathering as a result of increased billings under minimum volume commitments and higher fees and gathered volumes in the Anadarko Basin and a $9 million increase in the imbalance receivable associated with our annual fuel rate determination.

Our gathering and processing segment operation and maintenance and general and administrative expenses decreased by $17 million in 2016. The decrease was primarily due to $11 million of lower integration and other operating costs, a $6 million reduction in equipment rentals, a $4 million reduction in materials and supplies costs and a $1 million decrease in employee expenses. Workforce reductions announced in 2015 resulted in a $5 million reduction in payroll related costs and a $1 million decrease in severance charges. Additionally, there was a reduction in one-time project expenses of $9 million in 2016. These decreases were partially offset by a $12 million increase in payroll related costs due to increased short term incentive compensation, a $6 million increase in losses on the disposition of assets and a $2 million increase in allowance for doubtful accounts.

Our gathering and processing segment depreciation and amortization expense increased by $17 million in 2016 due to additional assets placed in service.

Our gathering and processing segment recognized impairments of $9 million in 2016 and $543 million in 2015. Our 2016 impairments consisted of $9 million in impairments on our Service Star business line. Our 2015 impairments were primarily related to a $508 million impairment on the carrying value of goodwill associated with our gathering and processing segment, a $25 million impairment of our Atoka assets and $10 million of impairments on our Service

Star business line.

Our gathering and processing segment taxes other than income tax increased by $2 million in 2016 due to higher estimated ad valorem taxes.

2015 compared to 2014. Our gathering and processing segment reported operating loss of $306 million in the year ended December 31, 2015 compared to operating income of $349 million in the year ended December 31, 2014. Operating income decreased $655 million primarily from impairment charges of $543 million related to the impairment of goodwill and long-lived assets, decreased gross margin of $84 million, an increase in depreciation and amortization of $35 million and an increase in taxes other than income tax of $5 million, partially offset by a decrease of $4 million in operation and maintenance and general and administrative expenses during the year ended December 31, 2015.

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Our gathering and processing segment revenues decreased $761 million. The decrease was primarily due to a $542 million reduction in NGL sales resulting from lower average NGL prices, partially offset by an increase in NGL volumes sold, a $226 million decrease from sales of natural gas as a result of lower average natural gas prices, a $14 million decrease due to lower gathered volumes and a $4 million decrease on third party measurement and communication services. These decreases were partially offset by increases in crude oil gathered volumes in the Williston Basin of $12 million, one-time project reimbursements of $11 million and a $2 million increase in unrealized gains on condensate and NGL derivatives during the year ended December 31, 2015.

Our gathering and processing segment gross margin decreased $84 million primarily due to a decrease in processing margins of $66 million resulting from the impact of lower average NGL prices and lower processed volumes in the Ark-La-Tex Basin offset by higher processed volumes in the Anadarko and Arkoma Basins. Also, gathering margins decreased due to reduced sales on natural gas length of $25 million and decreased gathering fees of $14 million, as a result of lower gathered volumes in the Arkoma and Ark-La-Tex Basins and lower average natural gas prices partially offset by higher gathered volumes in the Anadarko Basin, net of minimum volume payments, and lower revenues on third party measurement and communication services of $4 million. These decreases were partially offset by increases in crude oil gathered volumes in the Williston Basin of $12 million, one-time project reimbursements of $11 million and a $2 million increase in unrealized gains on condensate and NGL derivatives during the year ended December 31, 2015.

Our gathering and processing segment operation and maintenance and general and administrative expenses decreased $4 million primarily due to workforce reductions and lower payroll related costs of $13 million, lower write down of materials and supplies inventory of $4 million and lower losses on sale of assets of $2 million. These decreases were partially offset by expenses for one-time project costs of $9 million and payroll expenses for severance payments related to workforce reductions of $6 million.

Our gathering and processing segment depreciation and amortization increased $35 million due to additional assets placed in service.

Our gathering and processing segment recognized impairments of $543 million and $8 million in the years ended December 31, 2015 and 2014, respectively. Due to the continuing commodity price declines, the resulting decreases in forward commodity prices and forecasted producer activities, and an increase in the weighted average cost of capital, in its preparation of financial statements for the third quarter of 2015, the Partnership determined that the carrying value of goodwill associated with the gathering and processing reportable segment was completely impaired and recognized $508 million of impairment. The Partnership also determined that the carrying value of the Atoka assets were impaired and recognized $25 million of impairment. Additionally, the impairment on the Service Star business line increased $3 million during 2015, which was offset by lower impairment of assets held for sale of $1 million.

Our gathering and processing segment taxes other than income tax increased $5 million due to higher ad valorem taxes associated with additional assets placed in service of $2 million and the effect of a favorable settlement of a state and local tax dispute in 2014 for $3 million less than the previously recognized reserve.

Transportation and Storage

2016 compared to 2015. Our transportation and storage segment reported operating income of $189 million for 2016, as compared to an operating loss of $406 million for 2015. The difference of $595 million in operating income between periods was primarily due to $591 million of impairments recognized in 2015 related to goodwill and long-lived assets, a $39 million decrease in operation and maintenance and general and administrative expenses in 2016 and a $3 million decrease in taxes other than income tax in 2016. These increases were partially offset by a $35 million decrease in gross margin and a $3 million increase in depreciation and amortization expenses in 2016.

Our transportation and storage segment revenues decreased by $108 million in 2016. The decrease was primarily due to an $88 million decrease in revenues from lower natural gas sales associated with lower sales volumes and lower average sales prices and a $19 million decrease in revenues due to changes in the fair value of natural gas derivatives.

Our transportation and storage segment gross margin decreased by $35 million in 2016. The decrease was primarily due to a $19 million reduction in gross margin due to changes in the fair value of natural gas derivatives, a $17 million decrease in system management activities and a decrease of $5 million in firm transportation margins as a result of a decrease in contracted capacity. These decreases were partially offset by a $5 million increase in gross margin from transportation services for local distribution companies and a $1 million increase in gross margin from off-system transportation.

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Our transportation and storage segment operation and maintenance and general and administrative expenses decreased by $39 million in 2016. The decrease was primarily due to $29 million of lower integration and other contract services costs and a $3 million decrease in materials and supplies costs. Workforce reductions announced in 2015 resulted in a $10 million decrease in payroll related costs as well as $7 million in lower severance charges in 2016. These decreases were partially offset by a $6 million increase in losses on dispositions of assets and a $4 million increase in payroll related costs due to increased short term incentive compensation in 2016.

Our transportation and storage segment depreciation and amortization expense increased by $3 million in 2016 primarily due to additional assets placed in service.

Our transportation and storage segment recognized no impairments in 2016 as compared to $591 million of impairments in 2015. In 2015, we recognized impairments of $579 million on the carrying value of goodwill associated with the transportation and storage segment and impairments of $12 million on jurisdictional pipeline assets.

Our transportation and storage segment taxes other than income tax decreased by $3 million in 2016 due to favorable ad valorem assessments and appeal efforts.

Our transportation and storage segment recorded equity in earnings of equity method affiliate of $28 million in 2016 and $29 million in 2015 from our interest in SESH. The $1 million decrease in equity earnings from equity method affiliate is attributable to lower net income recognized by SESH in 2016.

2015 compared to 2014. Our transportation and storage segment reported operating loss of $406 million in the year ended December 31, 2015 compared to operating income of $237 million in the year ended December 31, 2014. Operating income decreased $643 million primarily resulting from impairment charges of $591 million primarily related to the impairment of goodwill, a decrease in gross margin of $49 million and a $7 million increase in depreciation and amortization expense, partially offset by a decrease in taxes other than income tax of $2 million and a decrease of $2 million in operation and maintenance and general and administrative expenses during the year ended December 31, 2015.

Our transportation and storage segment revenues decreased $445 million. The decrease was primarily due to a $358 million decrease in revenues from natural gas sales associated with lower sales volumes and lower average sales prices, $45 million of changes in the fair value of natural gas derivatives, a $23 million decrease in sales of NGLs collected under contractual arrangements resulting from lower NGL prices, a $12 million decrease from lower firm transportation revenues, a $6 million decrease in storage demand fees as well as lower rates on transportation services for local distribution companies of $4 million. These decreases were partially offset by increased margins from higher rates on off-system transportation services of $5 million for the year ended December 31, 2015.

Our transportation and storage segment gross margin decreased $49 million primarily due to lower margin on unrealized natural gas derivatives of $45 million, a decrease in sales of NGLs collected under contractual arrangements of $19 million resulting from lower NGL prices, lower firm transportation revenues of $12 million, a decrease in storage demand fees of $6 million as well as lower rates on transportation services for local distribution companies of $4 million. These decreases were partially offset by higher margins of $32 million related to realized gains on system optimization activities and increased margins from higher rates on off-system transportation services of $5 million for the year ended December 31, 2015.

Our transportation and storage segment operation and maintenance and general and administrative expenses decreased $2 million due to lower write down of materials and supplies inventory of $2 million and lower payroll related costs of $2 million related to workforce reductions. These decreases were offset by higher payroll expenses for severance payments related to workforce reductions of $2 million.

Our transportation and storage segment depreciation and amortization expense increased $7 million primarily due to the additional assets in service.

During 2015 our transportation and storage segment recognized impairment charges of $591 million. Due to continuing commodity price declines, the resulting decreases in forward commodity prices and forecasted producer activities and an increase in the weighted average cost of capital, the Partnership determined that the carrying value of goodwill associated with the transportation and storage reportable segment was completely impaired and as a result recognized impairment expense of $579 million in 2015. Additionally, we recognized an impairment on jurisdictional pipeline assets of $12 million in 2015.

Our transportation and storage segment taxes other than income tax decreased $2 million due to reduced ad valorem taxes.

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Our transportation and storage segment recorded equity in earnings of equity method affiliate of $29 million and $20 million for the years ended December 31, 2015 and 2014, respectively, from our interest in SESH. The $9 million increase in equity earnings from equity method affiliate is attributable to our increased interest in SESH for the year ended December 31, 2015 as compared to the year ended December 31, 2014.

Consolidated Information

	Year Ended December 31,		
	2016	2015	2014
	(In millions)		
Operating Income (Loss)	$385	$(712)	$586
Other Income (Expense):			
Interest expense	(99)	(90)	(70)
Equity in earnings of equity method affiliate	28	29	20
Other, net	—	2	(1)
Total Other Income (Expense)	(71)	(59)	(51)
Income (Loss) Before Income Taxes	314	(771)	535
Income tax expense	1	—	2
Net Income (Loss)	$313	$(771)	$533
Less: Net income (loss) attributable to noncontrolling interest	1	(19)	3
Net Income (Loss) attributable to limited partners	$312	$(752)	$530
Less: Series A Preferred Unit distributions	22	—	—
Net Income (Loss) attributable to common and subordinated units	$290	$(752)	$530

2016 compared to 2015

Net Income (Loss) attributable to limited partners. We reported net income attributable to limited partners of $312 million in 2016 compared to net loss attributable to limited partners of $752 million in 2015. The increase in net income attributable to the Partnership was primarily due to an increase in operating income of $1,097 million (inclusive of impairments discussed by segment above) partially offset by an increase in interest expense of $9 million and a decrease in equity earnings in equity method affiliate of $1 million (discussed by segment above).

Interest Expense. Interest expense increased by $9 million in 2016 due to higher interest rates on the Partnership's outstanding debt and an increase in the amount of outstanding variable rate debt.

2015 compared to 2014

Net Income (Loss) attributable to limited partners. We reported net loss attributable to limited partners of $752 million in the year ended December 31, 2015 compared to net income attributable to limited partners of $530 million in the year ended December 31, 2014. The decrease in net income attributable to limited partners of $1,282 million was primarily attributable to a decrease in operating income of $1,298 million (inclusive of impairments discussed by segment above) and an increase in interest expense of $20 million, partially offset by an increase in equity earnings in equity method affiliate of $9 million (discussed by segment above).

Interest Expense. Interest expense increased $20 million due to higher interest rates on the Partnership's outstanding debt and an increase in the amount of debt outstanding.

Reconciliations of Non-GAAP Financial Measures

The Partnership has included the non-GAAP financial measures Gross margin, Adjusted EBITDA, Adjusted interest expense, DCF and Distribution coverage ratio in this report based on information in its Consolidated Financial Statements. Gross margin, Adjusted EBITDA, Adjusted interest expense, DCF and Distribution coverage ratio are part of the performance measures that we use to manage the Partnership. For definitions and a description of management’s use of Gross margin, Adjusted EBITDA, Adjusted interest expense, DCF and Distribution coverage ratio, see “—Measures We Use to Evaluate Results of Operations” above.

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Provided below are reconciliations of Gross margin to total revenues, Adjusted EBITDA and DCF to net income attributable to limited partners, Adjusted EBITDA to net cash provided by operating activities and Adjusted interest expense to interest expense, the most directly comparable GAAP financial measures, on a historical basis, as applicable, for each of the periods indicated. Gross margin, Adjusted EBITDA, Adjusted interest expense, DCF and Distribution coverage ratio should not be considered as alternatives to net income, operating income, total revenues, cash flow from operating activities or any other measure of financial performance or liquidity presented in accordance with GAAP. These non-GAAP financial measures have important limitations as analytical tools because they exclude some but not all items that affect the most directly comparable GAAP financial measures. Additionally, because Gross margin, Adjusted EBITDA, Adjusted interest expense, DCF and Distribution coverage ratio may be defined differently by other companies in the Partnership’s industry, these measures may not be comparable to similarly titled measures of other companies, thereby diminishing their utility.

	Year Ended December 31,		
	2016	2015	2014
	(In millions)		
Reconciliation of Gross Margin to Total Revenues:			
Consolidated			
Product sales	$1,172	$1,334	$2,300
Service revenue	1,100	1,084	1,067
Total Revenues	2,272	2,418	3,367
Cost of natural gas and natural gas liquids (excluding depreciation and amortization)	1,017	1,097	1,914
Gross margin	$1,255	$1,321	$1,453
Reportable Segments			
Gathering and Processing			
Product sales	$1,081	$1,118	$1,907
Service revenue	559	545	517
Total Revenues	1,640	1,663	2,424
Cost of natural gas and natural gas liquids (excluding depreciation and amortization)	915	908	1,585
Gross margin	$725	$755	$839
Transportation and Storage			
Product sales	$479	$590	$1,009
Service revenue	545	542	568
Total Revenues	1,024	1,132	1,577
Cost of natural gas and natural gas liquids (excluding depreciation and amortization)	492	565	961
Gross margin	$532	$567	$616

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	Year Ended December 31,		
	2016	2015	2014
	(In millions, except Distribution coverage ratio)		
Reconciliation of Adjusted EBITDA and DCF to net income (loss) attributable to limited partners and calculation of Distribution coverage ratio:			
Net income (loss) attributable to limited partners	$312	$(752)	$530
Add:			
Depreciation and amortization expense	338	318	276
Interest expense, net of interest income	99	90	70
Income tax expense	1	—	2
EBITDA	$750	$(344)	$878
Add:			
Loss on extinguishment of debt	—	—	4
Distributions from equity method affiliate [1][2]	43	42	23
Non-cash equity based compensation	13	9	13
Other non-cash losses[3]	96	36	22
Impairments	9	1,134	8
Less:			
Other non-cash gains[4]	(10)	(27)	(46)
Noncontrolling Interest Share of Adjusted EBITDA	—	(20)	(1)
Equity in earnings of equity method affiliate	(28)	(29)	(20)
Adjusted EBITDA	$873	$801	$881
Less:			
Series A Preferred Unit distributions[5]	(31)	—	—
Adjusted interest expense[6]	(103)	(102)	(82)
Maintenance capital expenditures	(101)	(160)	(164)
Current income taxes	1	(1)	(1)
DCF	$639	$538	$634
Distributions related to common and subordinated unitholders[7]	$539	$534	$362
Distribution coverage ratio	1.18	1.01	1.75

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(1) Excludes $198 million in special distributions for the return of investment in SESH for the year ended December 31, 2014.

(2) Distributions from equity method affiliate includes a $28 million, $34 million and $23 million return on investment and a $15 million, $8 million and zero return of investment for the years ended December 31, 2016, 2015 and 2014, respectively.

(3) Other non-cash losses includes decreases in the fair value of derivatives, lower of cost or net realizable value adjustments, loss on sale of assets and write-downs of materials and supplies.

(4) Other non-cash gains includes lower of the cost or net realizable value adjustment recoveries upon the sale of the related inventory and increases in the fair value of derivatives.

(5) This amount represents the quarterly cash distributions on the Series A Preferred Units declared for the year ended December 31, 2016. In accordance with the Partnership Agreement, the Series A Preferred Unit distributions are deemed to have been paid out of available cash with respect to the quarter immediately preceding the quarter in which the distribution is made.

(6) See below for a reconciliation of Adjusted interest expense to Interest expense.

(7) Represents cash distributions declared for common and subordinated units outstanding as of each respective period. The Partnership began making quarterly distributions to common and subordinated unitholders the period beginning immediately after the closing of the Partnership's IPO in April 2014. Amounts for 2016 reflect estimated cash distributions for common and subordinated units outstanding for the quarter ended December 31, 2016.

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	Year Ended December 31,		
	2016	2015	2014
	(In millions)		
Reconciliation of Adjusted EBITDA to net cash provided by operating activities:			
Net cash provided by operating activities	$721	$726	$769
Interest expense, net of interest income	99	90	70
Net loss (income) attributable to noncontrolling interest	(1)	19	(3)
Income tax expense	1	—	2
Deferred income tax (expense) benefit	(2)	1	(1)
Equity in earnings of equity method affiliate, net of distributions[1][2]	—	(13)	(3)
Impairments	(9)	(1,134)	(8)
Non-cash equity based compensation	(13)	(9)	(13)
Other non-cash items	(14)	5	1
Changes in operating working capital which (provided) used cash:			
Accounts receivable	(4)	(15)	(53)
Accounts payable	40	29	140
Other, including changes in noncurrent assets and liabilities	(68)	(43)	(23)
EBITDA	$750	$(344)	$878
Add:			
Impairments	9	1,134	8
Non-cash equity based compensation	13	9	13
Loss on extinguishment of debt	—	—	4
Distributions from equity method affiliate [1][2]	43	42	23
Other non-cash losses[3]	96	36	22
Less:			
Other non-cash gains[4]	(10)	(27)	(46)
Noncontrolling Interest Share of Adjusted EBITDA	—	(20)	(1)
Equity in earnings of equity method affiliate	(28)	(29)	(20)
Adjusted EBITDA	$873	$801	$881

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(1) Excludes $198 million in special distributions for the return of investment in SESH for the year ended December 31, 2014.

(2) Distributions from equity method affiliate includes a $28 million, $34 million and $23 million return on investment and a $15 million, $8 million and zero return of investment for the years ended December 31, 2016, 2015 and 2014, respectively. Equity in earnings of equity method affiliate, net of distributions only includes those distributions representing a return on investment.

(3) Other non-cash losses includes decreases in the fair value of derivatives, lower of cost or net realizable value adjustments, loss on sale of assets and write-downs of materials and supplies.

(4) Other non-cash gains includes lower of the cost or net realizable value adjustment recoveries upon the sale of the related inventory and increases in the fair value of derivatives.

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	Year Ended December 31,		
	2016	2015	2014
	(In millions)		
Reconciliation of Adjusted interest expense to Interest expense:			
Interest Expense	$99	$90	$70
Add:			
Amortization of premium on long-term debt	6	5	7
Capitalized interest on expansion capital	1	10	8
Less:			
Amortization of debt expense	(3)	(3)	(3)
Adjusted interest expense	$103	$102	$82

Liquidity and Capital Resources

The Partnership's principal liquidity requirements are to finance its operations, fund capital expenditures and acquisitions, make cash distributions and satisfy any indebtedness obligations. We expect that our liquidity and capital resource needs will be met by cash on hand, operating cash flow, borrowings under our revolving credit facility, debt issuances and the issuance of equity. However, issuances of equity or debt in the capital markets and additional credit facilities may not be available to us on acceptable terms. Access to funds obtained through the equity or debt capital markets, particularly in the energy sector, has been constrained by a variety of market factors that have hindered the ability of energy companies to raise new capital or obtain financing at acceptable terms. On February 2, 2016, Standard & Poor's Ratings Services lowered its credit rating on the Partnership from an investment grade rating to a non-investment grade rating. The short-term rating on the Partnership was also reduced from an investment grade rating to a non-investment grade rating. As a result of the downgrade, the Partnership repaid its outstanding borrowings under the commercial paper program upon maturity and did not issue any additional commercial paper. Factors that contribute to our ability to raise capital through these channels depend on our financial condition, credit ratings and market conditions. Our ability to generate cash flow is subject to a number of factors, some of which are beyond our control. See Item 1A. "Risk Factors" for further discussion.

Working Capital

Working capital is the difference in our current assets and our current liabilities. Working capital is an indication of liquidity and potential need for short-term funding. The change in our working capital requirements are driven generally by changes in accounts receivable, accounts payable, commodity prices, credit extended to, and the timing of collections from, customers, and the level and timing of spending for maintenance and expansion activity. As of December 31, 2016, we had a working capital surplus of $34 million. We utilize our revolving credit facility to manage the timing of cash flows and fund short-term working capital deficits.

Cash Flows

The following tables reflect cash flows for the applicable periods:

	Year Ended December 31,		
	2016	2015	2014
	(In millions)		
Net cash provided by operating activities	$721	$726	$769
Net cash used in investing activities	$(367)	$(946)	$(815)

Net cash provided by (used in) financing activities	$(335)	$212	$(50)

Operating Activities

The decrease of $5 million, or 1%, in net cash provided by operating activities for the year ended December 31, 2016 as compared to the year ended December 31, 2015 is primarily due to timing of payments to suppliers, receipts from customers and changes in other working capital assets and liabilities.

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The decrease of $43 million, or 6%, in net cash provided by operating activities for the year ended December 31, 2015 as compared to the year ended December 31, 2014 is primarily due to lower gross margin, which was partially offset by the impact of timing of payments to suppliers, receipts from customers and changes in other working capital assets and liabilities.

Investing Activities

The decrease of $579 million, or 61%, in net cash used in investing activities for the year ended December 31, 2016 as compared to the year ended December 31, 2015 was primarily due to lower capital expenditures of $566 million, including the 2015 acquisition of the Monarch gas gathering system.

The increase of $131 million, or 16%, in net cash used in investing activities for the year ended December 31, 2015 as compared to the year ended December 31, 2014 was primarily due to higher capital expenditures of $112 million, including the $80 million associated with the acquisition of the Monarch gas gathering system.

Financing Activities

Net cash used in financing activities increased $547 million for the year ended December 31, 2016 as compared to the year ended December 31, 2015. Net cash used in financing activities decreased $262 million for the year ended December 31, 2015 as compared to the year ended December 31, 2014. Our primary financing activities consist of the following:

	Year Ended December 31,		
	2016	2015	2014
	(In millions)		
Repayment of Term Loan Agreements	$ —	$ —	$ (1,050)
Proceeds from Term Loan Agreements	—	450	—
Repayment of EOIT Term Loan	—	—	(250)
Repayment of EOIT Senior Note	—	—	(200)
Proceeds from Enable Midstream Partners, LP 2019, 2024 and 2044 Notes, net of issuance costs	—	—	1,635
Proceeds from issuance of Series A Preferred Units	362	—	—
Proceeds from issuance of common units	137	—	464
Net proceeds (repayments) of Revolving Credit Facility	326	310	(373)
(Repayments) proceeds from commercial paper program	(236)	(617)	253
Repayments of Notes Payable to Affiliates	(363)	—	—
Distributions	(561)	(531)	(529)

Sources of Liquidity

As of December 31, 2016, our sources of liquidity included:

- cash on hand;
- cash generated from operations;
- borrowings under our Revolving Credit facility; and
- capital raised through debt and equity markets.

Please see Note 10, “Debt” in the Notes to the Consolidated Financial Statements under Item 8, “Financial Statements and Supplementary Data” for a description of the Partnership’s debt agreements.

Equity Issuances

On November 29, 2016, the Partnership closed a public offering of 10,000,000 common units at a price to the public of $14.00 per common unit. In connection with the offering, the Partnership, the underwriters and an affiliate of ArcLight entered into an underwriting agreement that provided an option for the underwriters to purchase up to an additional 1,500,000 common units, with 75,719 common units to be sold by the Partnership and 1,424,281 to be sold by the affiliate of ArcLight. The underwriters

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exercised the option to purchase all of the additional common units, and the Partnership received proceeds (net of underwriting discounts, structuring fees and offering expenses) of $137 million from the offering.

On February 18, 2016, the Partnership completed the private placement of 14,520,000 Series A Preferred Units for a cash purchase price of $25.00 per Series A Preferred Unit, resulting in proceeds of $362 million, net of issuance costs. The Partnership incurred approximately $1 million of expenses related to the offering, which is accounted for as an offset to the proceeds. In connection with the closing of the private placement, the Partnership redeemed approximately $363 million of notes scheduled to mature in 2017 payable to a wholly-owned subsidiary of CenterPoint Energy.

On April 16, 2014, the Partnership completed the Offering of 25,000,000 common units, representing limited partner interests in the Partnership, at a price to the public of $20.00 per common unit. The Partnership received net proceeds of $464 million. The Partnership retained the net proceeds of the Offering for general partnership purposes, including the funding of expansion capital expenditures, and to pre-fund demand fees expected to be incurred over the next three years relating to certain expiring transportation and storage contracts.

Distribution Reinvestment Plan

In June 2016, the Partnership implemented a Distribution Reinvestment Plan (DRIP), which, beginning with the quarterly distribution for the quarter ended September 30, 2016, offers owners of our common and subordinated units the ability to purchase additional common units by reinvesting all or a portion of the cash distributions paid to them on their common or subordinated units. The Partnership will have the sole discretion to determine whether common units purchased under the DRIP will come from our newly issued common units or from common units purchased on the open market. The purchase price for newly issued common units will be the average of the high and low trading prices of the common units on the New York Stock Exchange-Composite Transactions for the five trading days immediately preceding the investment date. The purchase price for common units purchased on the open market will be the weighted average price of all common units purchased for the DRIP for the respective investment date. We can set a discount ranging from 0% to 5% for common units purchased pursuant to the DRIP. The discount is currently set at 0%. Participation in the DRIP is voluntary, and once enrolled, our unitholders may terminate participation at any time.

Capital Requirements

The midstream business is capital intensive and can require significant investment to maintain and upgrade existing operations, connect new wells to the system, organically grow into new areas and comply with environmental and safety regulations. Going forward, our capital requirements will consist of the following:

- maintenance capital expenditures, which are cash expenditures (including expenditures for the construction or development of new capital assets or the replacement, improvement or expansion of existing capital assets) made to maintain, over the long-term, our operating capacity or operating income; and
- expansion capital expenditures, which are cash expenditures incurred for acquisitions or capital improvements that we expect will increase our operating income or operating capacity over the long term.

For the year ending December 31, 2017, we estimate that expansion capital could range from approximately $455 million to $575 million and our maintenance capital could range from approximately $95 million to $125 million. Our future expansion capital expenditures may vary significantly from period to period based on commodity prices and the investment opportunities available to us. We expect to fund future capital expenditures from cash flow generated from our operations, borrowings under our Revolving Credit Facility, new debt offerings or the issuance of additional partnership units. Issuances of equity or debt in the capital markets may not, however, be available to us on acceptable terms.

Distributions

We intend to pay a minimum quarterly distribution of $0.2875 per common unit per quarter. We do not have a legal obligation to pay this distribution.

In determining the amount of available cash for distributions to holders of common and subordinated units, the Board of Directors determines the amount of cash reserves to set aside for our operations, including reserves for future working capital, maintenance capital expenditures, expansion capital expenditures, acquisitions and other matters, which will impact the amount of cash we are able to distribute to our unitholders. However, we expect that we will rely primarily upon external financing sources, including borrowings under our Revolving Credit Facility and issuances of debt and equity securities, as well as cash reserves, to fund our expansion capital expenditures including acquisitions. To the extent we are unable to finance growth externally and are unwilling to establish cash reserves to fund future expansions, our available cash for distributions will not significantly increase.

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In addition, because we distribute all of our available cash, we may not grow as quickly as businesses that reinvest their available cash to expand ongoing operations. To the extent we issue additional units in connection with any expansion capital expenditures including acquisitions, or to the extent we issue additional units ranking senior to our common units, the payment of distributions on those additional units may increase the risk that we will be unable to maintain or increase our per unit distribution level. There are no limitations in our partnership agreement or in the terms of our Revolving Credit Facility on our ability to issue additional units, including units ranking senior to the common units.

We paid or have authorized payment of the following cash distributions to common and subordinated unitholders during the years ended December 31, 2016, 2015 and 2014 (in millions, except for per unit amounts):

Quarter Ended	Record Date	Payment Date	Per Unit Distribution	Total Cash Distribution
December 31, 2016 (1)	February 21, 2017	February 28, 2017	$ 0.318	$ 137
September 30, 2016	November 14, 2016	November 22, 2016	$ 0.318	$ 134
June 30, 2016	August 16, 2016	August 23, 2016	$ 0.318	$ 134
March 31, 2016	May 6, 2016	May 13, 2016	$ 0.318	$ 134
December 31, 2015	February 2, 2016	February 12, 2016	$ 0.318	$ 134
September 30, 2015	November 3, 2015	November 13, 2015	$ 0.318	$ 134
June 30, 2015	August 3, 2015	August 13, 2015	$ 0.316	$ 134
March 31, 2015	May 5, 2015	May 15, 2015	$ 0.3125	$ 132
December 31, 2014	February 4, 2015	February 13, 2015	$ 0.30875	$ 130
September 30, 2014	November 4, 2014	November 14, 2014	$ 0.3025	$ 128
June 30, 2014 (2)	August 4, 2014	August 14, 2014	$ 0.2464	$ 104

(1) The board of directors of Enable GP declared this $0.318 per common unit cash distribution on February 10, 2017, to be paid on February 28, 2017, to unitholders of record at the close of business on February 21, 2017.

(2) The quarterly distribution for three months ended June 30, 2014 was prorated for the period beginning immediately after the closing of the Partnership's IPO, April 16, 2014 through June 30, 2014.

On February 14, 2014, May 14, 2014 and August 14, 2014, the Partnership distributed $114 million, $155 million and $22 million to the unitholders of record as of January 1, 2014, April 1, 2014 and April 1, 2014, respectively in accordance with the Partnership's First Amended and Restated Agreement of Limited Partnership.

On February 18, 2016, we completed the private placement of 14,520,000 Series A Preferred Units. Holders of the Series A Preferred Units receive a quarterly cash distribution on a non-cumulative basis if and when declared by the General Partner, and subject to certain adjustments, equal to an annual rate of: 10% on the stated liquidation preference of $25.00 from the date of original issue to, but not including, the five year anniversary of the original issue date; and thereafter a percentage of the stated liquidation preference equal to the sum of the three-month LIBOR plus 8.5%. The Series A Preferred Units rank senior to the Partnership's common units with respect to the payment of distributions and, unless full distributions are paid on the Series A Preferred Units with respect to a quarter, we cannot declare or pay a distribution on common or subordinated units with respect to that quarter. We intend to pay full distributions on Series A Preferred Units each quarter, however these distributions are not mandatory, and we do not have a legal obligation to pay these distributions. For more information on our Series A Preferred Units, see "Note 5. Enable Midstream Partners, LP Partners' Equity" included in "Item 8. Financial Statements and Supplementary Data—Notes to Audited Consolidated Financial Statements."

We paid or have authorized payment of the following cash distributions to holders of the Series A Preferred Units during the year ended December 31, 2016 (in millions, except for per unit amounts):

Quarter Ended	Record Date	Payment Date

			Per Unit Distribution	Total Cash Distribution
December 31, 2016[1]	February 10, 2017	February 15, 2017	$ 0.625	$ 9
September 30, 2016	November 1, 2016	November 14, 2016	$ 0.625	$ 9
June 30, 2016	August 2, 2016	August 12, 2016	$ 0.625	$ 9
March 31, 2016 [2]	May 6, 2016	May 13, 2016	$ 0.2917	$ 4

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(1) The board of directors of Enable GP declared a $0.625 per Series A Preferred Unit cash distribution on February 10, 2017, which was paid on February 15, 2017 to Series A Preferred unitholders of record at the close of business on February 10, 2017.

(2) The prorated quarterly distribution for the Series A Preferred Units is for a partial period beginning on February 18, 2016, and ending on March 31, 2016, which equates to $0.625 per unit on a full-quarter basis or $2.50 per unit on an annualized basis.

Contractual Obligations

In the ordinary course of business we enter into various contractual obligations for varying terms and amounts. The following table includes our contractual obligations and other commitments as of December 31, 2016 and our best estimate of the period in which the obligation will be settled:

	2017	2018-2019	2020-2021	After 2021	Total
Maturities of long-term debt(1)(2)	—	950	886	1,150	2,986
Noncancellable operating leases	10	7	—	—	17
Total contractual obligations	$ 10	$ 957	$ 886	$ 1,150	$3,003

(1) Contractual interest payments associated with long-term debt are $102 million, $185 million, $116 million and $677 million in 2017, 2018 through 2019, 2020 through 2021 and after 2021, respectively. The Revolving Credit Facility and 2015 Term Loan estimated contractual interest payments are calculated utilizing the respective variable interest rates as of December 31, 2016.

(2) Excludes premium (discount) on long-term debt of $17 million.

Off-Balance Sheet Arrangements

We do not have any off-balance sheet arrangements.

Critical Accounting Policies and Estimates

Our financial statements and the related notes thereto contain information that is pertinent to Management’s Discussion and Analysis. In preparing our financial statements, management is required to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and contingent liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Changes to these assumptions and estimates could have a material effect on the Partnership’s financial statements. However, the Partnership believes it has taken reasonable, but conservative, positions where assumptions and estimates are used in order to minimize the negative financial impact to the Partnership that could result if actual results vary from the assumptions and estimates. In management’s opinion, the areas of the Partnership where the most significant judgment is exercised for all Partnership segments includes the determination of impairment estimates of long-lived assets (including intangible assets) and goodwill, revenue recognition, valuation of assets and depreciable lives of property, plant and equipment and amortization methodologies related to intangible assets. The selection, application and disclosure of the following critical accounting estimates have been discussed with the Partnership’s board of directors. The Partnership discusses its significant accounting policies, including those that do not require management to make difficult, subjective, or complex judgments or estimates, in Note 1 of the Notes to Consolidated Financial Statements.

Impairment of Long-lived Assets (including Intangible Assets)

The Partnership periodically evaluates long-lived assets, including property, plant and equipment, and specifically identifiable intangibles other than goodwill, when events or changes in circumstances indicate that the carrying value of these assets may not be recoverable. The determination of whether an impairment has occurred is based on an estimate of undiscounted cash flows attributable to the assets, as compared to the carrying value of the assets. During the years ended December 31, 2016, 2015 and 2014, the Partnership recorded impairments of $9 million, $10 million and $7 million, respectively, on the Service Star business line, a component of our gathering and processing segment. During the year ended December 31, 2015, in connection with the preparation of the financial statements, the Partnership recorded a $25 million impairment on the Atoka assets in our gathering and processing segment and a $12 million impairment on jurisdictional pipelines in our transportation and storage segment. The

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Partnership recorded no other material impairments to long-lived assets in the years ended December 31, 2016, 2015 or 2014. Based upon review of forecasted undiscounted cash flows, none of the asset groups were at risk of failing step one of the impairment test. Further price declines, throughput declines, cost increases, regulatory or political environment changes and other changes in market conditions could reduce forecast undiscounted cash flows.

Impairment of Goodwill

The Partnership assesses its goodwill for impairment annually on October 1st, or more frequently if events or changes in circumstances indicate that the carrying value of goodwill may not be recoverable. Goodwill is assessed for impairment by comparing the fair value of the reporting unit with its book value, including goodwill. The Partnership utilizes the market or income approaches to estimate the fair value of the reporting unit, also giving consideration to the alternative cost approach. Under the market approach, historical and current year forecasted cash flows are multiplied by a market multiple to determine fair value. Under the income approach, anticipated cash flows over a period of years plus a terminal value are discounted to present value using appropriate discount rates. If the estimated fair value of the reporting unit is less than the carrying amount of the reporting unit, then a second step must be completed in order to determine the amount of the goodwill impairment that should be recorded. In the second step, the implied fair value of the reporting unit’s goodwill is determined by allocating the reporting unit’s fair value to all of its assets and liabilities other than goodwill (including any unrecognized intangible assets) in a manner similar to a purchase price allocation. The resulting implied fair value of the goodwill that results from the application of this second step is then compared to the carrying amount of the goodwill and an impairment charge is recorded for the difference. The Partnership performs its goodwill impairment testing one level below the transportation and storage and gathering and processing segment level at the operating segment level.

Because quoted market prices for the Partnership’s reporting units are not available, management must apply judgment in determining the estimated fair value of reporting units for purposes of performing the goodwill impairment test, when necessary. Management considered observable transactions in the market, as well as trading multiples and cost of capital for peers, to determine appropriate multiples and discount rates to apply against historical and forecasted cash flows. A lower fair value estimate in the future for any of the Partnership’s reporting units could result in a goodwill impairment. Factors that could trigger a lower fair value estimate include sustained price declines, throughput declines, cost increases, regulatory or political environment changes and other changes in market conditions such as decreased prices in market-based transactions for similar assets.

The Partnership performed the first step of our annual goodwill impairment analysis as of October 1, 2015, and determined that the carrying value of the gathering and processing and transportation and storage reportable segments exceeded fair value. The Partnership completed the second step of the goodwill impairment analysis by comparing the implied fair value of the reporting unit to the carrying amount of that goodwill and determined that goodwill was completely impaired in the amount of $1,087 million, which is included in Impairments on the Consolidated Statements of Income for the year ended December 31, 2015. As of December 31, 2016 and 2015, the Partnership had no goodwill recognized on its Consolidated Balance Sheet.

Revenue Recognition

The Partnership generates the majority of its revenues from midstream energy services, including natural gas gathering, processing, transportation and storage and crude oil gathering. The Partnership performs these services under various contractual arrangements, which include fee-based contract arrangements and arrangements pursuant to which it purchases and resells commodities in connection with providing the related service and earns a net margin for its fee. While the Partnership’s transactions vary in form, the essential element of each transaction is the use of its assets to transport a product or provide a processed product to a customer. The Partnership reflects revenue as Product sales and Service revenue on the Consolidated Statements of Income as follows:

Product sales: Product sales represent the sale of natural gas, NGLs, crude oil and condensate where the product is purchased and used in connection with providing the Partnership’s midstream services.

Service revenue: Service revenue represents all other revenue generated as a result of performing the Partnership’s midstream services.

Revenues for gathering, processing, transportation and storage services for the Partnership are recorded each month based on the current month’s estimated volumes, contracted prices (considering current commodity prices), historical seasonal fluctuations and any known adjustments. The estimates are reversed in the following month and customers are billed on actual volumes and contracted prices. Gas sales are calculated on current-month nominations and contracted prices. Revenues associated with the production of NGLs are estimated based on current-month estimated production and contracted prices. These amounts are reversed in the following month and the customers are billed on actual production and contracted prices. Estimated revenues

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are reflected in Accounts receivable, net or Accounts receivable—affiliated companies, as appropriate, on the Consolidated Balance Sheets and in Revenues on the Consolidated Statements of Income.

The Partnership recognizes revenue from natural gas gathering, processing, transportation and storage and crude oil gathering services to third parties as services are provided. Revenue associated with NGLs is recognized when the production is sold. The Partnership records deferred revenue when it receives consideration from a third party before achieving certain criteria that must be met for revenue to be recognized in accordance with GAAP. The Partnership had $34 million and $30 million of deferred revenues, including deferred revenue—affiliated companies, on the Consolidated Balance Sheets at each of December 31, 2016 and 2015, respectively.

Valuation of Assets

The application of business combination and impairment accounting requires the Partnership to use significant estimates and assumptions in determining the fair value of assets and liabilities. The acquisition method of accounting for business combinations requires the Partnership to estimate the fair value of assets acquired and liabilities assumed to allocate the proper amount of the purchase price consideration between goodwill and the assets that are depreciated and amortized. The Partnership records intangible assets separately from goodwill and amortizes intangible assets with finite lives over their estimated useful life as determined by management. The Partnership does not amortize goodwill but instead annually assesses goodwill for impairment.

In the year ended December 31, 2015, the Partnership completed an acquisition accounted for as a business combination as discussed in Note 3 of the Notes to Consolidated Financial Statements. As part of this acquisition, the Partnership engaged the services of third-party valuation experts to assist it in determining the fair value of the acquired assets and liabilities, including goodwill; however, the ultimate determination of those values is the responsibility of the Partnership’s management. The Partnership bases its estimates on assumptions believed to be reasonable, but which are inherently uncertain. These valuations require the use of management’s assumptions, which would not reflect unanticipated events and circumstances that may occur.

Depreciable Lives of Property, Plant and Equipment and Amortization Methodologies Related to Intangible Assets

The computation of depreciation expense requires judgment regarding the estimated useful lives and salvage value of assets at the time the assets are placed in service. As circumstances warrant, useful lives are adjusted when changes in planned use, changes in estimated production lives of affiliated natural gas basins or other factors indicate that a different life would be more appropriate. Such changes could materially impact future depreciation expense. Changes in useful lives that do not result in the impairment of an asset are recognized prospectively. The computation of amortization expense on intangible assets requires judgment regarding the amortization method used. Intangible assets are amortized on a straight-line basis over their useful lives using a method of amortization that reflects the pattern in which the economic benefits of the intangible asset are consumed.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

We are exposed to various market risks, including volatility in commodity prices and interest rates.

Commodity Price Risk

While we generate a substantial portion of our gross margin pursuant to fee-based contracts that include minimum volume commitments and/or demand fees, we are also directly and indirectly exposed to changes in the prices of natural gas, condensate and NGLs. The Partnership utilizes derivatives and forward commodity sales to mitigate the effects of price changes. We do not enter into risk management contracts for speculative purposes. For further information regarding our derivatives, see Note 12 of the Notes to Consolidated Financial Statements in Part II, Item 8. “Financial Statements and Supplementary Data.”

Based on our forecasted volumes, prices and contractual arrangements, we estimate approximately 15% of our total gross margin for the twelve months ending December 31, 2017 will be directly exposed to changes in commodity prices, excluding the impact of hedges and contractual floors related to commodity prices in certain agreements. Since December 31, 2016, we have entered into additional derivative contracts to further manage our exposure to commodity price risk for the twelve months ending December 31, 2017.

Commodity price risk is estimated as the potential loss in value resulting from a hypothetical 10% decline in prices over the next 12 months. Based on a sensitivity analysis for the twelve months ending December 31, 2017, a 10% decrease in prices from forecasted levels would decrease net income by approximately $10 million for natural gas and ethane and $10 million for NGLs, excluding ethane, and condensate, excluding the impact of hedges.

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Interest Rate Risk

Our current interest rate risk exposure is related primarily to our debt portfolio. The majority of our debt portfolio is comprised of fixed rate debt, which mitigates the impact of fluctuations in interest rates. Future issuances of long-term debt could be impacted by increases in interest rates, which could result in higher interest costs. Borrowings under our Revolving Credit Facility, 2015 Term Loan Agreement and any issuances under our commercial paper program could be at a variable interest rate and could expose us to the risk of increasing interest rates. Based upon the $1,086 million outstanding borrowings under the 2015 Term Loan Agreement and Revolving Credit Facility as of December 31, 2016, and holding all other variables constant, a 100 basis-point, or 1%, increase in interest rates would increase our annual interest expense by approximately $11 million.

Item 8. Financial Statements and Supplementary Data

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of Enable GP, LLC and
Unitholders of Enable Midstream Partners, LP
Oklahoma City, Oklahoma

We have audited the accompanying consolidated balance sheets of Enable Midstream Partners, LP and subsidiaries (the "Partnership") as of December 31, 2016 and 2015, and the related consolidated statements of income, comprehensive income, cash flows, and partners’ equity for each of the three years in the period ended December 31, 2016. These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on the 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. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Enable Midstream Partners, LP and subsidiaries as of December 31, 2016 and 2015, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2016, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Partnership's internal control over financial reporting as of December 31, 2016, based on the criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 21, 2017 expressed an unqualified opinion on the Partnership's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
February 21, 2017

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of Enable GP, LLC and
Unitholders of Enable Midstream Partners, LP
Oklahoma City, Oklahoma

We have audited the internal control over financial reporting of Enable Midstream Partners, LP and subsidiaries (the "Partnership") as of December 31, 2016, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Partnership's management is responsible for 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 Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Partnership's internal control over financial reporting based on our audit.

We conducted our audit 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 effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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

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

In our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2016, based on the criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2016 of the Partnership and our report dated February 21, 2017 expressed an unqualified opinion on those financial statements.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
February 21, 2017

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ENABLE MIDSTREAM PARTNERS, LP
CONSOLIDATED STATEMENTS OF INCOME

	Year Ended December 31,		
	2016	2015	2014
	(In millions, except per unit data)		
Revenues (including revenues from affiliates (Note 14)):			
Product sales	$1,172	$1,334	$2,300
Service revenue	1,100	1,084	1,067
Total Revenues	2,272	2,418	3,367
Cost and Expenses (including expenses from affiliates (Note 14)):			
Cost of natural gas and natural gas liquids (excluding depreciation and amortization shown separately)	1,017	1,097	1,914
Operation and maintenance	367	419	420
General and administrative	98	103	107
Depreciation and amortization	338	318	276
Impairments (Note 8, Note 11)	9	1,134	8
Taxes other than income taxes	58	59	56
Total Cost and Expenses	1,887	3,130	2,781
Operating (Loss) Income	385	(712)	586
Other Income (Expense):			
Interest expense (including expenses from affiliates (Note 14))	(99)	(90)	(70)
Equity in earnings of equity method affiliate	28	29	20
Other, net	—	2	(1)
Total Other Income (Expense)	(71)	(59)	(51)
Income (Loss) Before Income Taxes	314	(771)	535
Income tax expense	1	—	2
Net Income (Loss)	$313	$(771)	$533
Less: Net income (loss) attributable to noncontrolling interest	1	(19)	3
Net Income (Loss) Attributable to Limited Partners	$312	$(752)	$530
Less: Series A Preferred Unit distributions (Note 5)	22	—	—
Net Income (Loss) Attributable to Common and Subordinated Units (Note 4)	$290	(752)	$530
Basic earnings (loss) per unit (Note 4)			
Common units	$0.69	$(1.78)	$1.29
Subordinated units	$0.68	$(1.78)	$1.28
Diluted earnings (loss) per unit (Note 4)			
Common units	$0.69	$(1.78)	$1.29
Subordinated units	$0.68	$(1.78)	$1.28

See Notes to the Consolidated Financial Statements

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ENABLE MIDSTREAM PARTNERS, LP
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Year Ended December 31,		
	2016	2015	2014
	(In millions)		
Net Income (Loss)	$313	$(771)	$533
Comprehensive Income (Loss)	313	(771)	533
Less: Comprehensive income (loss) attributable to noncontrolling interest	1	(19)	3
Comprehensive Income (Loss) Attributable to Enable Midstream Partners, LP	$312	$(752)	$530

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ENABLE MIDSTREAM PARTNERS, LP
CONSOLIDATED BALANCE SHEETS

	December 31,	
	2016	2015
	(In millions, except units)	
Current Assets:		
Cash and cash equivalents	$6	$4
Restricted cash	17	—
Accounts receivable, net	249	245
Accounts receivable—affiliated companies	13	21
Inventory	41	53
Gas imbalances	41	23
Other current assets	29	35
Total current assets	396	381
Property, Plant and Equipment:		
Property, plant and equipment	11,567	11,293
Less accumulated depreciation and amortization	1,424	1,162
Property, plant and equipment, net	10,143	10,131
Other Assets:		
Intangible assets, net	306	333
Investment in equity method affiliate	329	344
Other	38	37
Total other assets	673	714
Total Assets	$11,212	$11,226
Current Liabilities:		
Accounts payable	$181	$248
Accounts payable—affiliated companies	3	9
Short-term debt	—	236
Taxes accrued	30	30
Gas imbalances	35	25
Accrued compensation	37	23
Customer deposits	31	18
Other	45	26
Total current liabilities	362	615
Other Liabilities:		
Accumulated deferred income taxes, net	10	8
Notes payable—affiliated companies	—	363
Regulatory liabilities	19	18
Other	34	20
Total other liabilities	63	409
Long-Term Debt	2,993	2,671
Commitments and Contingencies (Note 15)		
Partners’ Equity:		
Series A Preferred Units (14,520,000 issued and outstanding at December 31, 2016 and 0 issued and outstanding at December 31, 2015)	362	—
Common units (224,535,454 issued and outstanding at December 31, 2016 and 214,541,422 issued and outstanding at December 31, 2015, respectively)	3,737	3,714
	3,683	3,805

Subordinated units (207,855,430 issued and outstanding at December 31, 2016 and December 31, 2015, respectively)		
Noncontrolling interest	12	12
Total Partners' Equity	7,794	7,531
Total Liabilities and Partners' Equity	$11,212	$11,226

See Notes to the Consolidated Financial Statements

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ENABLE MIDSTREAM PARTNERS, LP
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2016	2015	2014
	(In millions)		
Cash Flows from Operating Activities:			
Net income (loss)	$313	$(771)	$533
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation and amortization	338	318	276
Deferred income taxes	2	(1)	1
Impairments	9	1,134	8
Loss on sale/retirement of assets	17	5	—
Equity in earnings of equity method affiliate, net of distributions	—	5	3
Equity based compensation	13	9	13
Amortization of debt expense and discount (premium)	(3)	(2)	(1)
Changes in other assets and liabilities:			
Accounts receivable, net	(4)	9	52
Accounts receivable—affiliated companies	8	6	1
Inventory	12	10	7
Gas imbalance assets	(18)	22	(35)
Other current assets	6	2	17
Other assets	(1)	(4)	5
Accounts payable	(34)	—	(138)
Accounts payable—affiliated companies	(6)	(29)	(2)
Gas imbalance liabilities	10	12	—
Other current liabilities	45	6	29
Other liabilities	14	(5)	—
Net cash provided by operating activities	721	726	769
Cash Flows from Investing Activities:			
Capital expenditures	(383)	(869)	(837)
Acquisitions, net of cash acquired	—	(80)	—
Proceeds from sale of assets	1	3	13
Return of investment in equity method affiliate	15	8	198
Investment in equity method affiliate	—	(8)	(189)
Net cash used in investing activities	(367)	(946)	(815)
Cash Flows from Financing Activities:			
Repayment of long term debt	—	—	(1,500)
Proceeds from long term debt, net of issuance costs	—	450	1,635
Proceeds from revolving credit facility	1,734	585	122
Repayment of revolving credit facility	(1,408)	(275)	(495)
Increase (decrease) in short-term debt	(236)	(17)	253
Repayment of notes payable—affiliated companies	(363)	—	—
Proceeds from issuance of common units	137	—	464
Proceeds from issuance of Series A Preferred Units, net of issuance costs	362	—	—
Distributions	(561)	(531)	(529)
Net cash provided by (used in) financing activities	(335)	212	(50)
Net Increase (Decrease) in Cash, Cash Equivalents and Restricted Cash	19	(8)	(96)
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	4	12	108

Cash, Cash Equivalents and Restricted Cash at End of Period	$23	$4	$12

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ENABLE MIDSTREAM PARTNERS, LP
CONSOLIDATED STATEMENTS OF PARTNERS' EQUITY

	Series A Preferred Units		Common Units		Subordinated Units		Noncontrolling Interest	Total Partners' Equity
	Units	Value	Units	Value	Units	Value	Value	Value
	(In millions)							
Balance as of December 31, 2013	—	$—	390	$8,148	—	$—	$ 33	$8,181
Conversion to subordinated units	—	—	(208)	(4,372)	208	4,372	—	—
Net income	—	—	—	349	—	181	3	533
Issuance of IPO common units	—	—	25	464	—	—	—	464
Issuance of common units upon interest acquisition of SESH	—	—	6	161	—	—	—	161
Distributions	—	—	—	(410)	—	(114)	(5)	(529)
Equity based compensation, net of units for employee taxes	—	—	1	13	—	—	—	13
Balance as of December 31, 2014	—	$—	214	$4,353	208	$4,439	$ 31	$8,823
Net loss	—	—	—	(379)	—	(373)	(19)	(771)
Issuance of common units upon interest acquisition of SESH	—	—	—	1	—	—	—	1
Distributions	—	—	—	(270)	—	(261)	—	(531)
Equity based compensation, net of units for employee taxes	—	—	—	9	—	—	—	9
Balance as of December 31, 2015	—	$—	214	$3,714	208	$3,805	$ 12	$7,531
Net income	—	22	—	147	—	143	1	313
Issuance of Series A Preferred Units	15	362	—	—	—	—	—	362
Issuance of common units	—	—	10	137	—	—	—	137
Distributions	—	(22)	—	(274)	—	(265)	(1)	(562)
Equity based compensation, net of units for employee taxes	—	—	—	13	—	—	—	13
Balance as of December 31, 2016	15	$362	224	$3,737	208	$3,683	$ 12	$7,794

See Notes to the Consolidated Financial Statements

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ENABLE MIDSTREAM PARTNERS, LP
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

(1) Summary of Significant Accounting Policies

Organization

Enable Midstream Partners, LP (Partnership) is a Delaware limited partnership formed on May 1, 2013 by CenterPoint Energy, OGE Energy and ArcLight, pursuant to the terms of the MFA. The Partnership's assets and operations are organized into two reportable segments: (i) gathering and processing and (ii) transportation and storage. The gathering and processing segment primarily provides natural gas and crude oil gathering and natural gas processing services to our producer customers. The transportation and storage segment provides interstate and intrastate natural gas pipeline transportation and storage services primarily to our producer, power plant, LDC and industrial end-user customers. The Partnership's natural gas gathering and processing assets are primarily located in Oklahoma, Texas, Arkansas and Louisiana and serve natural gas production in the Anadarko, Arkoma and Ark-La-Tex Basins. Crude oil gathering assets are located in North Dakota and serve crude oil production in the Bakken Shale formation of the Williston Basin. The Partnership's natural gas transportation and storage assets consist primarily of an interstate pipeline system extending from western Oklahoma and the Texas Panhandle to Louisiana, an interstate pipeline system extending from Louisiana to Illinois, an intrastate pipeline system in Oklahoma, and our investment in SESH, a pipeline extending from Louisiana to Alabama.

CenterPoint Energy and OGE Energy each have 50% of the management interests in Enable GP. Enable GP is the general partner of the Partnership and has no other operating activities. Enable GP is governed by a board made up of two representatives designated by each of CenterPoint Energy and OGE Energy, along with the Partnership's Chief Executive Officer and three independent board members CenterPoint Energy and OGE Energy mutually agreed to appoint. CenterPoint Energy and OGE Energy also own a 40% and 60% interest, respectively, in the incentive distribution rights held by Enable GP.

At December 31, 2016, CenterPoint Energy held approximately 54.1% of the Partnership's common and subordinated units, or 94,151,707 common units and 139,704,916 subordinated units, and OGE Energy held approximately 25.7% of the Partnership's common and subordinated units, or 42,832,291 common units and 68,150,514 subordinated units. Additionally, CenterPoint Energy holds 14,520,000 Series A Preferred Units. The limited partner interests of the Partnership have limited voting rights on matters affecting the business. As such, limited partners do not have rights to elect the Partnership's General Partner (Enable GP) on an annual or continuing basis and may not remove Enable GP without at least a 75% vote by all unitholders, including all units held by the Partnership's limited partners, and Enable GP and its affiliates, voting together as a single class.

For the period from December 31, 2013 through May 29, 2014, the financial statements reflect a 24.95% interest in SESH. For the period of May 30, 2014 through June 29, 2015, the financial statements reflect a 49.90% interest in SESH. On June 12, 2015, CenterPoint Energy exercised its put right with respect to a 0.1% interest in SESH. Pursuant to the put right, on June 30, 2015, CenterPoint Energy contributed its remaining 0.1% interest in SESH to the Partnership in exchange for 25,341 common units. As of December 31, 2016, the Partnership owned a 50% interest in SESH. See Note 9 for further discussion of SESH.

In addition, for the years ended December 31, 2016, 2015 and 2014, the Partnership held a 50% ownership interest in Atoka and consolidated Atoka in its Consolidated Financial Statements as EOIT acted as the managing member of Atoka and had control over the operations of Atoka.

On April 16, 2014, the Partnership completed the IPO of 25,000,000 common units at a price to the public of $20.00 per common unit. The Partnership received net proceeds of $464 million from the sale of the common units, after deducting underwriting discounts and commissions, the structuring fee and offering expenses. In connection with the IPO, underwriters exercised their option to purchase 3,750,000 additional common units, which were fulfilled with units held by ArcLight. As a result, the Partnership did not receive any proceeds from the sale of common units pursuant to the exercise of the underwriters' option to purchase additional common units. The exercise of the underwriters' option to purchase additional common units did not affect the total number of units outstanding or the amount of cash needed to pay the minimum quarterly distribution on all outstanding units. The Partnership retained the net proceeds of the IPO for general partnership purposes, including the funding of expansion capital expenditures, and to pre-fund demand fees expected to be incurred over the next three years relating to certain expiring transportation and storage contracts. In connection with the IPO, 139,704,916 of CenterPoint Energy's common units and 68,150,514 of OGE Energy's common units were converted into subordinated units.

Basis of Presentation

The accompanying consolidated financial statements and related notes of the Partnership have been prepared pursuant to the rules and regulations of the SEC and GAAP.

For a description of the Partnership’s reportable segments, see Note 18.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Revenue Recognition

The Partnership generates the majority of its revenues from midstream energy services, including natural gas gathering, processing, transportation and storage and crude oil gathering. The Partnership performs these services under various contractual arrangements, which include fee-based contract arrangements and arrangements pursuant to which it purchases and resells commodities in connection with providing the related service and earns a net margin for its fee. While the Partnership’s transactions vary in form, the essential element of each transaction is the use of its assets to transport a product or provide a processed product to a customer. The Partnership reflects revenue as Product sales and Service revenue on the Consolidated Statements of Income as follows:

Product sales: Product sales represent the sale of natural gas, NGLs, crude oil and condensate where the product is purchased and used in connection with providing the Partnership’s midstream services.

Service revenue: Service revenue represents all other revenue generated as a result of performing the Partnership’s midstream services.

Revenues for gathering, processing, transportation and storage services for the Partnership are recorded each month based on the current month’s estimated volumes, contracted prices (considering current commodity prices), historical seasonal fluctuations and any known adjustments. The estimates are reversed in the following month and customers are billed on actual volumes and contracted prices. Gas sales are calculated on current-month nominations and contracted prices. Revenues associated with the production of NGLs are estimated based on current-month estimated production and contracted prices. These amounts are reversed in the following month and the customers are billed on actual production and contracted prices. Estimated revenues are reflected in Accounts receivable, net or Accounts receivable—affiliated companies, as appropriate, on the Consolidated Balance Sheets and in Revenues on the Consolidated Statements of Income.

The Partnership recognizes revenue from natural gas gathering, processing, transportation and storage and crude oil gathering services to third parties as services are provided. Revenue associated with NGLs is recognized when the production is sold. The Partnership records deferred revenue when it receives consideration from a third party before achieving certain criteria that must be met for revenue to be recognized in accordance with GAAP. The Partnership had $34 million and $30 million of deferred revenues, including deferred revenue—affiliated companies, on the Consolidated Balance Sheets at December 31, 2016 and 2015, respectively.

The Partnership relies on certain key natural gas producer customers for a significant portion of natural gas and NGLs supply. The Partnership relies on certain key utilities for a significant portion of transportation and storage demand.

The Partnership depends on third-party facilities to transport and fractionate NGLs that it delivers to third parties at the inlet of their facilities. Additionally, for the years ended December 31, 2016, 2015 and 2014, one third party purchased approximately 22%, 18% and 21%, respectively, of the NGLs delivered off our system, which accounted for approximately $129 million, $108 million and $235 million, or 6%, 4% and 7%, respectively, of total revenues. Other than revenues from affiliates discussed in Note 14, there are no other revenue concentrations with individual customers in the years ended December 31, 2016, 2015 and 2014.

Natural Gas and Natural Gas Liquids Purchases

Cost of natural gas and natural gas liquids represents cost of our natural gas and natural gas liquids purchased exclusive of depreciation, Operation and maintenance and General and administrative expenses and consists primarily of product and fuel

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costs. Estimates for gas purchases are based on estimated volumes and contracted purchase prices. Estimated gas purchases are included in Accounts Payable or Accounts Payable-affiliated companies, as appropriate, on the Consolidated Balance Sheets and in Cost of natural gas and natural gas liquids, excluding Depreciation and amortization on the Consolidated Statements of Income.

Operation and Maintenance and General and Administrative Expense

Operation and maintenance expense represents the cost of our service related revenues and consists primarily of labor expenses, lease costs, utility costs, insurance premiums and repairs and maintenance expenses directly related with the operations of assets. General and administrative expense represents cost incurred to manage the business. This expense includes cost of general corporate services, such as treasury, accounting, legal, information technology and human resources and all other expenses necessary or appropriate to the conduct of business. Any Operation and maintenance expense and General and administrative expense associated with product sales is immaterial.

Environmental Costs

The Partnership expenses or capitalizes environmental expenditures, as appropriate, depending on their future economic benefit. The Partnership expenses amounts that relate to an existing condition caused by past operations that do not have future economic benefit. The Partnership records undiscounted liabilities related to these future costs when environmental assessments and/or remediation activities are probable and the costs can be reasonably estimated. There are no material amounts accrued at December 31, 2016 or 2015.

Depreciation and Amortization Expense

Depreciation is computed using the straight-line method based on economic lives or a regulatory-mandated recovery period. Amortization of intangible assets is computed using the straight-line method over the respective lives of the intangible assets.

The computation of depreciation expense requires judgment regarding the estimated useful lives and salvage value of assets at the time the assets are placed in service. As circumstances warrant, useful lives are adjusted when changes in planned use, changes in estimated production lives of affiliated natural gas basins or other factors indicate that a different life would be more appropriate. Such changes could materially impact future depreciation expense. Changes in useful lives that do not result in the impairment of an asset are recognized prospectively. The computation of amortization expense on intangible assets requires judgment regarding the amortization method used. Intangible assets are amortized on a straight-line basis over their useful lives using a method of amortization that reflects the pattern in which the economic benefits of the intangible asset are consumed.

Income Taxes

Upon conversion to a limited partnership on May 1, 2013, the Partnership’s earnings are no longer subject to income tax (other than Texas state margin taxes and taxes associated with the Partnership’s corporate subsidiaries, Enable Midstream Services and Enable Muskogee Intrastate Transmission) and are taxable at the individual partner level. For more information, see Note 16.

We account for deferred income taxes related to the federal and state jurisdictions using the asset and liability method. Under this method, deferred tax assets and liabilities are recognized for the future taxes attributable to the difference between financial statement carrying amounts of assets and liabilities and their respective tax basis. Deferred tax assets are also recognized for the future tax benefits attributable to the expected utilization of tax net operating loss carryforwards. In the event future utilization is determined to be unlikely, a valuation allowance is provided to reduce the tax benefits from such assets. Deferred tax assets and liabilities are measured using enacted tax rates in effect for the period in which the temporary differences and carryforwards are expected to be recovered or settled. The effect of a change in tax rates is recognized in the period which includes the enactment date. The Partnership recognizes interest and penalties as a component of income tax expense.

Cash and Cash Equivalents

The Partnership considers cash equivalents to be short-term, highly liquid investments with maturities of three months or less from the date of purchase. The Consolidated Balance Sheets have $6 million and $4 million of cash and cash equivalents as of December 31, 2016 and 2015, respectively.

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Restricted Cash

Restricted cash consists of cash which is restricted by agreements with third parties. The Consolidated Balance Sheets have $17 million of restricted cash as of December 31, 2016. The Partnership had no restricted cash as of December 31, 2015.

Accounts Receivable and Allowance for Doubtful Accounts

Accounts receivable are recorded at the invoiced amount and do not typically bear interest. The determination of the allowance for doubtful accounts requires management to make estimates and judgments regarding our customers' ability to pay. The allowance for doubtful accounts is determined based upon specific identification and estimates of future uncollectable amounts. On an ongoing basis, we evaluate our customers' financial strength based on aging of accounts receivable, payment history and review of other relevant information, including ratings agency credit ratings and alerts, publicly available reports and news releases, and bank and trade references. It is the policy of management to review the outstanding accounts receivable at least quarterly, giving consideration to historical bad debt write-offs, the aging of receivables and specific customer circumstances that may impact their ability to pay the amounts due. Based on this review, management determined that a $3 million allowance for doubtful accounts was required as of December 31, 2016, and no allowance for doubtful accounts was required as of December 31, 2015.

Inventory

Materials and supplies inventory is valued at cost and is subsequently recorded at the lower of cost or net realizable value. During the years ended December 31, 2016 and 2014, the Partnership recorded write-downs to net realizable value related to materials and supplies inventory disposed or identified as excess or obsolete of $1 million and $9 million, respectively. There were no material write-downs related to materials and supplies inventory for the year ended December 31, 2015. Materials and supplies are recorded to inventory when purchased and, as appropriate, subsequently charged to operation and maintenance expense on the Consolidated Statements of Income or capitalized to property, plant and equipment on the Consolidated Balance Sheets when installed.

Natural gas inventory is held, through the transportation and storage segment, to provide operational support for the intrastate pipeline deliveries and to manage leased intrastate storage capacity. Natural gas liquids inventory is held, through the gathering and processing segment, due to timing differences between the production of certain natural gas liquids and ultimate sale to third parties. Natural gas and natural gas liquids inventory is valued using moving average cost and is subsequently recorded at the lower of cost or net realizable value. During the years ended December 31, 2016, 2015 and 2014, the Partnership recorded write-downs to net realizable value related to natural gas and natural gas liquids inventory of $3 million, $13 million and $4 million, respectively. The cost of gas associated with sales of natural gas and natural gas liquids inventory is presented in Cost of natural gas and natural gas liquids, excluding depreciation and amortization on the Consolidated Statements of Income.

	December 31,	
	2016	2015
	(In millions)	
Materials and supplies	$ 30	$ 34
Natural gas and natural gas liquids inventories	11	19
Total	$ 41	$ 53

Gas Imbalances

Gas imbalances occur when the actual amounts of natural gas delivered from or received by the Partnership's pipeline system differ from the amounts scheduled to be delivered or received. Imbalances are due to or due from shippers and operators and can be settled in cash or natural gas depending on contractual terms. The Partnership values all imbalances at individual, or where appropriate an average of, current market indices applicable to the Partnership's operations, not to exceed net realizable value.

Long-Lived Assets (including Intangible Assets)

The Partnership records property, plant and equipment and intangible assets at historical cost. Newly constructed plant is added to plant balances at cost which includes contracted services, direct labor, materials, overhead, transportation costs and capitalized interest. Replacements of units of property are capitalized as plant. For assets that belong to a common plant account, the replaced plant is removed from plant balances and charged to Accumulated depreciation. For assets that do not belong to a common plant account, the replaced plant is removed from plant balances with the related accumulated depreciation and the remaining balance net of any salvage proceeds is recorded as a loss in the Consolidated Statements of Income as Operation and maintenance expense. The Partnership expenses repair and maintenance costs as incurred. Repair, removal and maintenance costs are included in the Consolidated Statements of Income as Operation and maintenance expense.

Assessing Impairment of Long-lived Assets (including Intangible Assets) and Goodwill

The Partnership periodically evaluates long-lived assets, including property, plant and equipment, and specifically identifiable intangibles other than goodwill, when events or changes in circumstances indicate that the carrying value of these assets may not be recoverable. The determination of whether an impairment has occurred is based on an estimate of undiscounted cash flows attributable to the assets, as compared to the carrying value of the assets. For more information, see Note 11.

The Partnership assesses its goodwill for impairment annually on October 1st, or more frequently if events or changes in circumstances indicate that the carrying value of goodwill may not be recoverable. Goodwill is assessed for impairment by comparing the fair value of the reporting unit with its book value, including goodwill. The Partnership utilizes the market or income approaches to estimate the fair value of the reporting unit, also giving consideration to the alternative cost approach. Under the market approach, historical and current year forecasted cash flows are multiplied by a market multiple to determine fair value. Under the income approach, anticipated cash flows over a period of years plus a terminal value are discounted to present value using appropriate discount rates. If the estimated fair value of the reporting unit is less than the carrying amount of the reporting unit, then a second step must be completed in order to determine the amount of the goodwill impairment that should be recorded. In the second step, the implied fair value of the reporting unit's goodwill is determined by allocating the reporting unit's fair value to all of its assets and liabilities other than goodwill (including any unrecognized intangible assets) in a manner similar to a purchase price allocation. The resulting implied fair value of the goodwill that results from the application of this second step is then compared to the carrying amount of the goodwill and an impairment charge is recorded for the difference. The Partnership performs its goodwill impairment testing one level below the transportation and storage and gathering and processing segment level at the operating segment level. For more information, see Note 8.

Regulatory Assets and Liabilities

The Partnership applies the guidance for accounting for regulated operations to portions of the transportation and storage segment. The Partnership's rate-regulated businesses recognize removal costs as a component of depreciation expense in accordance with regulatory treatment. As of each of December 31, 2016 and 2015, these removal costs of $19 million and $18 million, respectively, are classified as Regulatory liabilities in the Consolidated Balance Sheets.

Capitalization of Interest and Allowance for Funds Used During Construction

Allowance for funds used during construction (AFUDC) represents the approximate net composite interest cost of borrowed funds and a reasonable return on the equity funds used for construction. Although AFUDC increases both utility plant and earnings, it is realized in cash when the assets are included in rates for combined entities that apply guidance for accounting for regulated operations. Capitalized interest represents the approximate net composite interest cost of borrowed funds used for construction. Interest and AFUDC are capitalized as a component of projects under construction and will be amortized over the assets' estimated useful lives. During the years ended December 31, 2016, 2015 and 2014, the Partnership capitalized interest and AFUDC of $4 million, $10 million and $8 million, respectively.

Derivative Instruments

The Partnership is exposed to various market risks. These risks arise from transactions entered into in the normal course of business. At times, the Partnership utilizes derivative instruments such as physical forward contracts, financial futures and swaps to mitigate the impact of changes in commodity prices on its operating results and cash flows. Such derivatives are recognized in the Partnership’s Consolidated Balance Sheets at their fair value unless the Partnership elects hedge accounting or the normal purchase and sales exemption for qualified physical transactions. For derivative instruments not designated as hedging instruments, the gain or loss on the derivative is recognized in Product sales in the Consolidated Statements of Income. A derivative may be designated as a normal purchase or normal sale if the intent is to physically receive or deliver the product for use or sale in the normal course of business.

The Partnership’s policies prohibit the use of leveraged financial instruments. A leveraged financial instrument, for this purpose, is a transaction involving a derivative whose financial impact will be based on an amount other than the notional amount or volume of the instrument.

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Fair Value Measurements

The Partnership determines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. As required, the Partnership utilizes valuation techniques that maximize the use of observable inputs (levels 1 and 2) and minimize the use of unobservable inputs (level 3) within the fair value hierarchy included in current accounting guidance. The Partnership generally applies the market approach to determine fair value. This method uses pricing and other information generated by market transactions for identical or comparable assets and liabilities. Assets and liabilities are classified within the fair value hierarchy based on the lowest level (least observable) input that is significant to the measurement in its entirety.

Equity Based Compensation

The Partnership awards equity based compensation to officers, directors and employees under the Long Term Incentive Plan. All equity based awards to officers, directors and employees under the Long Term Incentive Plan, including grants of performance units, time-based phantom units (phantom units) and time-based restricted units (restricted units) are recognized in the Consolidated Statements of Income based on their fair values. The fair value of the phantom units and restricted units are based on the closing market price of the Partnership's common unit on the grant date. The fair value of the performance units is estimated on the grant date using a lattice-based valuation model that factors in information, including the expected distribution yield, expected price volatility, risk-free interest rate and the probable outcome of the market condition, over the expected life of the performance units. Compensation expense for the phantom unit and restricted unit awards is a fixed amount determined at the grant date fair value and is recognized as services are rendered by employees over a vesting period. The vesting of the performance unit awards is also contingent upon the probable outcome of the market condition. Depending on forfeitures and actual vesting, the compensation expense recognized related to the awards could increase or decrease.

Reverse Unit Split

On March 25, 2014, the Partnership effected a 1 for 1.279082616 reverse unit split. All unit and per unit amounts presented within the consolidated financial statements reflect the effects of the reverse unit split.

Third Amended and Restated Agreement of Limited Partnership of Enable Midstream Partners, LP

On February 18, 2016, in connection with the closing of the private placement of 14,520,000 Series A Preferred Units and pursuant to the Purchase Agreement, the General Partner adopted the Third Amended and Restated Agreement of Limited Partnership which, among other things, authorized and established the terms of the Series A Preferred Units and the other series of preferred units that are issuable upon conversion of the Series A Preferred Units. For further information related to the issuance of the Series A Preferred Units, see Note 5.

Fourth Amended and Restated Agreement of Limited Partnership of Enable Midstream Partners, LP

On June 22, 2016, the General Partner adopted the Fourth Amended and Restated Agreement of Limited Partnership (the Partnership Agreement), which changed the last permitted distribution date with respect to each fiscal quarter from 45 days following the close of such quarter to 60 days following the close of such quarter.

(2) New Accounting Pronouncements

Revenue from Contracts with Customers

In May 2014, the FASB issued ASU No. 2014-09, “Revenue from Contracts with Customers (Topic 606),” which supersedes the revenue recognition requirements in “Revenue Recognition (Topic 605).” Topic 606 is based on the core principle that revenue is recognized to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled to in exchange for those goods or services. Topic 606 also requires additional disclosure about the nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers, including significant judgments and changes in judgments and assets recognized from costs incurred to obtain or fulfill a contract.

Topic 606 is effective for fiscal years beginning after December 15, 2017, and interim periods within those years, with early adoption permitted in 2017, however we do not plan to adopt the standard early. Entities will have the option to apply the standard using a full retrospective or modified retrospective adoption method. The Partnership expects to adopt this ASU using the modified retrospective method. Our evaluation of the impact on our Consolidated Financial Statements and related disclosures is ongoing

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and not complete. In connection with our assessment work, we formed an implementation work team, completed training on the Topic 606 revenue recognition model and are continuing our review of contracts relative to the provisions of Topic 606.

Leases

In February 2016, the FASB issued ASU 2016-02, "Leases (Topic 842)." This standard requires, among other things, that lessees recognize the following for all leases (with the exception of short-term leases) at the commencement date: (1) a lease liability, which is a lessee's obligation to make lease payments arising from a lease, measured on a discounted basis; and (2) a right-of-use asset, which is an asset that represents the lessee's right to use, or control the use of, a specified asset for the lease term. Lessees and lessors must apply a modified retrospective transition approach for leases existing at, or entered into after, the beginning of the earliest comparative period presented in the financial statements. The Partnership expects to adopt this standard in the first quarter of 2019 and is currently evaluating the impact of this standard on our Consolidated Financial Statements and related disclosures. In connection with our assessment work, we formed an implementation work team and are continuing a review of our contracts relative to the provisions of the lease standard.

Share-Based Compensation

In March 2016, the FASB issued ASU No. 2016-09, "Compensation—Stock Compensation (Topic 718)." This standard makes several modifications to Topic 718 related to the accounting for forfeitures, employer tax withholding on share-based compensation and the financial statement presentation of excess tax benefits or deficiencies. ASU 2016-09 also clarifies the statement of cash flows presentation for certain components of share-based awards. The standard is effective for interim and annual reporting periods beginning in 2017, although early adoption is permitted. The Partnership will adopt the amendment in the fourth quarter of 2017, and does not expect the adoption of this standard to have a material impact on our Consolidated Financial Statements and related disclosures.

Financial Instruments—Credit Losses
In June 2016, the FASB issued ASU No. 2016-13, "Financial Instruments—Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments." This standard requires entities to measure all expected credit losses of financial assets held at a reporting date based on historical experience, current conditions and reasonable and supportable forecasts in order to record credit losses in a more timely matter. ASU 2016-13 also amends the accounting for credit losses on available-for-sale debt securities and purchased financial assets with credit deterioration. The standard is effective for interim and annual reporting periods beginning after December 15, 2019, although early adoption is permitted for interim and annual periods beginning after December 15, 2018. The guidance requires application using a modified retrospective method. The Partnership does not expect the adoption of this standard to have a material impact on our Consolidated Financial Statements and related disclosures.

Statement of Cash Flows

In August 2016, the FASB issued ASU No. 2016-15, "Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments." This standard is intended to reduce existing diversity in practice in how certain transactions are presented on the statement of cash flows. The standard is effective for interim and annual reporting periods beginning after December 15, 2017, although early adoption is permitted. The guidance requires application using a retrospective transition method. The Partnership will adopt ASU No. 2016-15 in the first quarter of 2017 and has determined the amendment will not have a material impact on our Consolidated Financial Statements and related disclosures.

Income Taxes

In October 2016, the FASB issued ASU No. 2016-16, “Income Taxes (Topic 740): Intra-Entity Transfers of Assets Other Than Inventory.” This standard requires entities to recognize the tax consequences of an intra-entity transfer of an asset other than inventory when the transfer occurs. The standard is effective for interim and annual reporting periods beginning after December 15, 2017, although early adoption is permitted as of the beginning of an annual period (i.e., only in the first interim period). The guidance requires application using a modified retrospective approach. The Partnership is currently evaluating the impact, if any, the adoption of this standard will have on our Consolidated Financial Statements and related disclosures.

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Restricted Cash

In November 2016, the FASB issued ASU No. 2016-18, “Statement of Cash Flows (Topic 230): Restricted Cash.” The standard is intended to provide specific guidance on the cash flow classification and presentation of changes in restricted cash. The Partnership early adopted the amendment in the fourth quarter of 2016, using a retrospective basis. As of December 31, 2016, the Partnership had restricted cash of $17 million. The Partnership had no restricted cash as of December 31, 2015.

(3) Acquisition

On April 22, 2015, Enable entered into an agreement with Monarch Natural Gas, LLC, pursuant to which the Partnership agreed to acquire approximately 106 miles of gathering pipeline, approximately 5,000 horsepower of associated compression, right-of-ways and certain other midstream assets that provide natural gas gathering services in the Greater Granite Wash area of Texas. The transaction closed on May 1, 2015. The aggregate purchase price for this transaction was approximately $80 million, which was funded from cash generated from operations and borrowings under our Revolving Credit Facility.

The acquisition was accounted for as a business combination. During the third quarter of 2015, the Partnership, with the assistance of a third-party valuation expert, finalized the purchase price allocation as of May 1, 2015.

Purchase price allocation (in millions):	
Property, plant and equipment	$51
Intangibles	10
Goodwill	19
Total	$80

The Partnership recognized intangible assets related to customer relationships. The acquired intangible assets will be amortized on a straight-line basis over the estimated customer contract life of approximately 15 years. Goodwill recognized from the acquisition primarily relates to the value created from additional growth opportunities and greater operating leverage in the Anadarko Basin. See Note 8 for further information related to the Partnership’s goodwill impairment. The Partnership incurred less than $1 million of acquisition costs associated with this transaction, which are included in General and administrative expense in the Consolidated Statements of Income.

(4) Earnings Per Limited Partner Unit

Basic and diluted earnings per limited partner unit is calculated by dividing net income (loss) allocable to common and subordinated unitholders by the weighted average number of common and subordinated units outstanding during the period. Any common units issued during the period are included on a weighted average basis for the days in which they were outstanding. The dilutive effect of the unit-based awards discussed in Note 17 was less than $0.01 per unit during the years ended December 31, 2016, 2015 and 2014.

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The following table illustrates the Partnership's calculation of earnings (loss) per unit for common and subordinated units:

	Year Ended December 31,		
	2016	2015	2014
	(In millions, except per unit data)		
Net income (loss)	$313	$(771)	$533
Net income (loss) attributable to noncontrolling interest	1	(19)	3
Series A Preferred Unit distribution	22	—	—
General partner interest in net income	—	—	—
Net income (loss) available to common and subordinated unitholders	$290	$(752)	$530
Net income (loss) allocable to common units	$148	$(381)	$339
Net income (loss) allocable to subordinated units	142	(371)	191
Net income (loss) available to common and subordinated unitholders	$290	$(752)	$530
Net income (loss) allocable to common units	$148	$(381)	$339
Dilutive effect of Series A Preferred Unit distribution	—	—	—
Dilutive effect of performance units	—	—	—
Diluted net income (loss) allocable to common units	148	(381)	339
Diluted net income (loss) allocable to subordinated units	142	(371)	191
Total	$290	$(752)	$530
Basic weighted average number of outstanding			
Common units	216	214	264
Subordinated units	208	208	148
Total	424	422	412
Basic earnings (loss) per unit			
Common units	$0.69	$(1.78)	$1.29
Subordinated units	$0.68	$(1.78)	$1.28
Basic weighted average number of outstanding common units	216	214	264
Dilutive effect of Series A Preferred Units	—	—	—
Dilutive effect of performance units	—	—	—
Diluted weighted average number of outstanding common units	216	214	264
Diluted weighted average number of outstanding subordinated units	208	208	148
Total	424	422	412
Diluted earnings (loss) per unit			
Common units	$0.69	$(1.78)	$1.29
Subordinated units	$0.68	$(1.78)	$1.28

(5) Enable Midstream Partners, LP Partners' Equity

The Partnership Agreement requires that, within 60 days subsequent to the end of each quarter, the Partnership distribute all of its available cash (as defined in the Partnership Agreement) to unitholders of record on the applicable record date. The Partnership did not make distributions for the period that began on April 1, 2014 and ended on April 15, 2014, the day prior to the closing of the IPO, other than the required distributions to CenterPoint Energy, OGE Energy and ArcLight under the Partnership Agreement.

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On February 14, 2014, May 14, 2014 and August 14, 2014, the Partnership distributed $114 million, $155 million and $22 million to the unitholders of record as of January 1, 2014, April 1, 2014 and April 1, 2014, respectively in accordance with the Partnership's First Amended and Restated Agreement of Limited Partnership.

The Partnership paid or has authorized payment of the following cash distributions to common and subordinated unitholders during 2016, 2015 and 2014 (in millions, except for per unit amounts):

Quarter Ended	Record Date	Payment Date	Per Unit Distribution	Total Cash Distribution
December 31, 2016(1)	February 21, 2017	February 28, 2017	$ 0.318	$ 137
September 30, 2016	November 14, 2016	November 22, 2016	$ 0.318	$ 134
June 30, 2016	August 16, 2016	August 23, 2016	$ 0.318	$ 134
March 31, 2016	May 6, 2016	May 13, 2016	$ 0.318	$ 134
December 31, 2015	February 2, 2016	February 12, 2016	$ 0.318	$ 134
September 30, 2015	November 3, 2015	November 13, 2015	$ 0.318	$ 134
June 30, 2015	August 3, 2015	August 13, 2015	$ 0.316	$ 134
March 31, 2015	May 5, 2015	May 15, 2015	$ 0.3125	$ 132
December 31, 2014	February 4, 2015	February 13, 2015	$ 0.30875	$ 130
September 30, 2014	November 4, 2014	November 14, 2014	$ 0.3025	$ 128
June 30, 2014 (2)	August 4, 2014	August 14, 2014	$ 0.2464	$ 104

(1) The board of directors of Enable GP declared this $0.318 per common unit cash distribution on February 10, 2017, to be paid on February 28, 2017, to common and subordinated unitholders of record at the close of business on February 21, 2017.

(2) The quarterly distribution for three months ended June 30, 2014 was prorated for the period beginning immediately after the closing of the Partnership's IPO, April 16, 2014 through June 30, 2014.

The Partnership paid or has authorized payment of the following cash distributions to holders of the Series A Preferred Units during 2016 (in millions, except for per unit amounts):

Quarter Ended	Record Date	Payment Date	Per Unit Distribution	Total Cash Distribution
December 31, 2016(1)	February 10, 2017	February 15, 2017	$ 0.625	$ 9
September 30, 2016	November 1, 2016	November 14, 2016	$ 0.625	$ 9
June 30, 2016	August 2, 2016	August 12, 2016	$ 0.625	$ 9
March 31, 2016(2)	May 6, 2016	May 13, 2016	$ 0.2917	$ 4

(1) The board of directors of Enable GP declared this $0.625 per Series A Preferred Unit cash distribution on February 10, 2017, which was paid on February 15, 2017 to Series A Preferred unitholders of record at the close of business on February 10, 2017.

(2) The prorated quarterly distribution for the Series A Preferred Units is for a partial period beginning on February 18, 2016, and ending on March 31, 2016, which equates to $0.625 per unit on a full-quarter basis or $2.50 per unit on an annualized basis.

General Partner Interest and Incentive Distribution Rights

Enable GP owns a non-economic general partner interest in the Partnership and thus will not be entitled to distributions that the Partnership makes prior to the liquidation of the Partnership in respect of such general partner interest. Enable GP currently holds incentive distribution rights that entitle it to receive increasing percentages, up to a maximum of 50.0%, of the cash the Partnership distributes from operating surplus (as defined in the Partnership Agreement) in excess of $0.330625 per unit per quarter. The maximum distribution of 50.0% does not include any distributions that Enable GP or its affiliates may receive on common units or subordinated units that they own.

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Subordinated Units

General

As of December 31, 2016, all subordinated units are held by CenterPoint Energy and OGE Energy. These units are considered subordinated because for a period of time, defined by the Partnership Agreement as the subordination period, the subordinated units will not be entitled to receive any distributions until the common units have received distributions of available cash each quarter from operating surplus in an amount equal to the minimum quarterly distribution plus any arrearages on minimum quarterly distributions on the common units from prior quarters. In addition, the subordinated units are not entitled to arrearages on minimum quarterly distributions. On the expiration of the subordination period, the subordinated units will convert to common units on a one-for-one basis.

Subordination Period

The subordination period began on the closing date of the IPO and expires on the first to occur of the following dates: (1) the first business day following the distribution of available cash in respect of any quarter beginning with the quarter ending June 30, 2017 that the following tests are met: (a) distributions of available cash from operating surplus on each of the outstanding common units and subordinated units equal or exceed $1.15 per unit (the annualized minimum quarterly distribution) for each of the three consecutive, non-overlapping four-quarter periods immediately preceding that date; (b) the adjusted operating surplus generated during each of the three consecutive, non-overlapping four-quarter periods immediately preceding that date equaled or exceeded the sum $1.15 (the annualized minimum quarterly distribution) on all of the common units and subordinated units outstanding during those periods on a fully diluted weighted average basis; and (c) there are no arrearages in the payment of the minimum quarterly distributions on the common units or (2) the first business day following the distribution of available cash in respect of any quarter beginning with the quarter ending June 30, 2015 that the following tests are met: (a) distributions of available cash from operating surplus on each of the outstanding common units and subordinated units equal to or exceeding $1.725 per unit (150% of the annualized minimum quarterly distribution) for the four consecutive quarter period immediately preceding that date; (b) the adjusted operating surplus generated during the four consecutive quarter period immediately preceding that date equaled or exceed $1.725 per unit (150% of the annualized minimum quarterly distribution) on all of the common units and subordinated units outstanding during that period on a fully diluted weighted average basis plus the corresponding incentive distribution rights; and (c) there are no arrearages in the payment of the minimum quarterly distributions on the common units.

Series A Preferred Units

On February 18, 2016, the Partnership completed the private placement of 14,520,000 Series A Preferred Units representing limited partner interests in the Partnership for a cash purchase price of $25.00 per Series A Preferred Unit, resulting in proceeds of $362 million, net of issuance costs. The Partnership incurred approximately $1 million of expenses related to the offering, which is shown as an offset to the proceeds. In connection with the closing of the private placement, the Partnership redeemed approximately $363 million of notes scheduled to mature in 2017 payable to a wholly-owned subsidiary of CenterPoint Energy.

Pursuant to the Partnership Agreement, the Series A Preferred Units:

- rank senior to the Partnership’s common units with respect to the payment of distributions and distribution of assets upon liquidation, dissolution and winding up;
- have no stated maturity;
- are not subject to any sinking fund; and
- will remain outstanding indefinitely unless repurchased or redeemed by the Partnership or converted into its common units in connection with a change of control.

Holders of the Series A Preferred Units receive a quarterly cash distribution on a non-cumulative basis if and when declared by the General Partner, and subject to certain adjustments, equal to an annual rate of: 10% on the stated liquidation preference of $25.00 from the date of original issue to, but not including, the five year anniversary of the original issue date; and thereafter a percentage of the stated liquidation preference equal to the sum of the three-month LIBOR plus 8.5%.

At any time on or after five years after the original issue date, the Partnership may redeem the Series A Preferred Units, in whole or in part, from any source of funds legally available for such purpose, by paying $25.50 per unit plus an amount equal to all accumulated and unpaid distributions thereon to the date of redemption, whether or not declared. In addition, the Partnership (or a third-party with its prior written consent) may redeem the Series A Preferred Units following certain changes in the methodology employed by ratings agencies, changes of control or fundamental transactions as set forth in the Partnership

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Agreement. If, upon a change of control or certain fundamental transactions, the Partnership (or a third-party with its prior written consent) does not exercise this option, then the holders of the Series A Preferred Units have the option to convert the Series A Preferred Units into a number of common units per Series A Preferred Unit as set forth in the Partnership Agreement. The Series A Preferred Units are also required to be redeemed in certain circumstances if they are not eligible for trading on the New York Stock Exchange.

Holders of Series A Preferred Units have no voting rights except for limited voting rights with respect to potential amendments to the Partnership Agreement that have a material adverse effect on the existing terms of the Series A Preferred Units, the issuance by the Partnership of certain securities, approval of certain fundamental transactions and as required by law.

Upon the transfer of any Series A Preferred Unit to a non-affiliate of CenterPoint Energy, the Series A Preferred Units will automatically convert into a new series of preferred units (the Series B Preferred Units) on the later of the date of transfer and the second anniversary of the date of issue. The Series B Preferred Units will have the same terms as the Series A Preferred Units except that unpaid distributions on the Series B Preferred Units will accrue on a cumulative basis until paid.

On February 18, 2016, the Partnership entered into a registration rights agreement with CenterPoint Energy, pursuant to which, among other things, the Partnership gave CenterPoint Energy certain rights to require the Partnership to file and maintain a registration statement with respect to the resale of the Series A Preferred Units and any other series of preferred units or common units representing limited partner interests in the Partnership that are issuable upon conversion of the Series A Preferred Units.

2016 Equity Issuance

On November 29, 2016, the Partnership closed a public offering of 10,000,000 common units at a price to the public of $14.00 per common unit. In connection with the offering, the Partnership, the underwriters and an affiliate of ArcLight entered into an underwriting agreement that provided an option for the underwriters to purchase up to an additional 1,500,000 common units, with 75,719 common units to be sold by the Partnership and 1,424,281 to be sold by the affiliate of ArcLight. The underwriters exercised the option to purchase all of the additional common units, and the Partnership received proceeds (net of underwriting discounts, structuring fees and offering expenses) of $137 million from the offering.

(6) Property, Plant and Equipment

Property, plant and equipment includes the following:

	Weighted Average Useful Lives (Years)	December 31, 2016	2015
		(In millions)	
Property, plant and equipment, gross:			
Gathering and Processing	37	$6,987	$6,478
Transportation and Storage	36	4,498	4,444
Construction work-in-progress		82	371
Total		$11,567	$11,293
Accumulated depreciation:			
Gathering and Processing		681	510
Transportation and Storage		743	652

Total accumulated depreciation	1,424	1,162
Property, plant and equipment, net	$10,143	$10,131

The Partnership recorded depreciation expense of $311 million, $291 million and $249 million during the years ended December 31, 2016, 2015 and 2014, respectively.

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(7) Intangible Assets, Net

As of December 31, 2016, the Partnership has $405 million in intangible assets associated with customer relationships due to the acquisition of Enogex and Monarch Natural Gas, LLC.

Intangible assets consist of the following:

	December 31, 2016	2015
	(In millions)	
Customer relationships:		
Total intangible assets	$405	$405
Accumulated amortization	99	72
Net intangible assets	$306	$333

The Partnership determined that intangible assets related to customer relationships have a weighted average useful life of 15 years. Intangible assets do not have any significant residual value or renewal options of existing terms. There are no intangible assets with indefinite useful lives.

The Partnership recorded amortization expense of $27 million, $27 million and $27 million during the years ended December 31, 2016, 2015 and 2014, respectively. The following table summarizes the Partnership's expected amortization of intangible assets for each of the next five years:

	2017	2018	2019	2020	2021
	(In millions)				
Expected amortization of intangible assets	$27	$ 27	$ 27	$ 27	$ 27

(8) Goodwill

For the periods ended prior to September 30, 2015, the goodwill associated with the gathering and processing reportable segment is primarily related to the acquisitions of Enogex, Waskom and Monarch. The Partnership recognized $438 million of goodwill as a result of the acquisition of Enogex, which occurred at the time of the formation of the Partnership in 2013. The $579 million of goodwill associated with the transportation and storage reportable segment was related to the original acquisitions of EGT and MRT in 1997 by predecessors of the Partnership. Subsequent to the completion of the October 1, 2014 annual test and previous interim assessment as of December 31, 2014, the crude oil and natural gas industry was impacted by further commodity price declines, which consequently resulted in decreased producer activity in certain regions in which the Partnership operates. Due to the continuing commodity price declines, the resulting decreases in forward commodity prices and forecasted producer activities, and an increase in the weighted average cost of capital, the Partnership determined that the impact on our forecasted discounted cash flows for our gathering and processing and transportation and storage reportable segments would be significantly reduced. As a result, when the Partnership performed our annual goodwill impairment analysis as of October 1, 2015, we determined that goodwill was completely impaired in the amount of $1,087 million, which is included in Impairments on the Consolidated Statements of Income for the year ended December 31, 2015. As a result, the Partnership did not have any goodwill recorded as of December 31, 2016 and 2015.

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The change in carrying amount of goodwill in each of our reportable segments is as follows:

	Gathering and Processing	Transportation and Storage	Total
	(in millions)		
Balance as of December 31, 2014	$489	$ 579	$1,068
Acquisition of Monarch	19	—	19
Goodwill impairment	(508)	(579)	(1,087)
Balance as of December 31, 2015	$—	$ —	$—
Balance as of December 31, 2016	$—	$ —	$—

(9) Investment in Equity Method Affiliate

The Partnership uses the equity method of accounting for investments in entities in which it has an ownership interest between 20% and 50% and exercises significant influence.

For the period December 31, 2013 through May 29, 2014, the Partnership held a 24.95% interest in SESH, which is accounted for as an investment in equity method affiliate, and CenterPoint Energy indirectly owned a 25.05% interest in SESH. Pursuant to the MFA, that interest could be contributed to the Partnership upon exercise of certain put or call rights, under which CenterPoint Energy would contribute to the Partnership CenterPoint Energy's retained interest in SESH at a price equal to the fair market value of such interest at the time the put right or call right is exercised. On May 13, 2014, CenterPoint Energy exercised its put right with respect to a 24.95% interest in SESH. Pursuant to the put right, on May 30, 2014, CenterPoint Energy contributed a 24.95% interest in SESH to the Partnership in exchange for 6,322,457 common units, which had a fair value of $161 million based upon the closing market price of the Partnership's common units. For the period from May 30, 2014 through June 29, 2015, the Partnership held a 49.90% interest in SESH. On June 12, 2015, CenterPoint Energy exercised its put right with respect to its remaining 0.1% interest in SESH. Pursuant to the put right, on June 30, 2015, CenterPoint Energy contributed a 0.1% interest in SESH to the Partnership in exchange for 25,341 common units, which had a fair value of $1 million based upon the closing market price of the Partnership's common units. Spectra Energy Partners, LP owns the remaining 50% interest in SESH. Pursuant to the terms of the SESH LLC Agreement, if, at any time, CenterPoint Energy has a right to receive less than 50% of our distributions through its limited partner interest in the Partnership and its economic interest in Enable GP, or does not have the ability to exercise certain control rights, Spectra Energy Partners, LP could have the right to purchase our interest in SESH at fair market value, subject to certain exceptions. As of December 31, 2016, the Partnership owned a 50% interest in SESH.

In connection with CenterPoint Energy's exercise of its put right with respect to its 24.95% interest in SESH, the parties agreed to allocate the distributions for the quarter ended June 30, 2014 on (i) the SESH interest acquired by Enable and (ii) the Enable units issued to CenterPoint Energy for the SESH interest pro rata based on the time each party held the relevant interest. On July 25, 2014, the Partnership received a $7 million distribution from SESH for the three month period ended June 30, 2014, representing the Partnership's 49.90% interest in SESH. Under the terms of the agreement, the Partnership made a payment of approximately $1 million to CenterPoint Energy related to the additional 24.95% interest during the quarter ending September 30, 2014.

On June 13, 2014, SESH made a special distribution of the proceeds of its $400 million senior note issuance, less debt issuance costs, which resulted in a $198 million return of investment to the Partnership. In August 2014, the Partnership contributed $187 million to SESH which was utilized to repay SESH's $375 million senior notes due August 2014, increasing the book value of Enable's 50% investment in SESH. The Partnership and other members of

SESH intend to contribute or otherwise return the remaining special distribution to SESH as necessary for general SESH purposes, including capital expenditures associated with SESH's expansion plans.

The Partnership shares operations of SESH with Spectra Energy Partners, LP under service agreements. The Partnership is responsible for the field operations of SESH. SESH reimburses each party for actual costs incurred, which are billed based upon a combination of direct charges and allocations. During the years ended December 31, 2016, 2015 and 2014, the Partnership billed SESH $13 million, $12 million and $13 million, respectively, associated with these service agreements.

The Partnership includes equity in earnings of equity method affiliate under the Other Income (Expense) caption in the Consolidated Statements of Income for the years ended December 31, 2016, 2015 and 2014.

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Investment in Equity Method Affiliate:

	(In millions)
Balance as of December 31, 2013	$ 198
Interest acquisition of SESH	161
Return of investment from SESH refinancing	(198)
Additional investment in SESH	187
Equity in earnings of equity method affiliate	20
Contributions to equity method affiliate	3
Distributions from equity method affiliate[1]	(23)
Balance as of December 31, 2014	348
Interest acquisition of SESH	1
Equity in earnings of equity method affiliate	29
Contributions to equity method affiliate	8
Distributions from equity method affiliate[1]	(42)
Balance as of December 31, 2015	344
Equity in earnings of equity method affiliate	28
Distributions from equity method affiliate[1]	(43)
Balance as of December 31, 2016	$ 329

(1) Distributions from equity method affiliate includes a $28 million, $34 million and $23 million return on investment and a $15 million, $8 million and zero return of investment for the years ended December 31, 2016, 2015 and 2014, respectively.

Equity in Earnings of Equity Method Affiliate:

	Year Ended December 31,		
	2016	2015	2014
	(In millions)		
SESH	$28	$ 29	$ 20

Distributions from Equity Method Affiliate:

	Year Ended December 31,		
	2016	2015	2014
	(In millions)		
SESH [1]	$43	$ 42	$ 23

(1) Excludes $198 million in special distributions for the return of investment in SESH for the year ended December 31, 2014.

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Summarized financial information of SESH:

	December 31, 2016	December 31, 2015
	(In millions)	
Balance Sheet Data:		
Current assets	$31	$45
Property, plant and equipment, net	1,110	1,127
Total assets	$1,141	$1,172
Current liabilities	$18	$18
Long-term debt	397	397
Members' equity	726	757
Total liabilities and members' equity	$1,141	$1,172
Reconciliation:		
Investment in SESH	$329	$344
Less: Capitalized interest on investment in SESH	(1)	(1)
Add: Basis differential, net of amortization	35	36
The Partnership's share of members' equity	$363	$379

	Year Ended December 31, 2016	2015	2014
	(In millions)		
Income Statement Data:			
Revenues	$115	$115	$108
Operating income	$73	$71	$69
Net income	$55	$57	$48

(10) Debt

The following table presents the Partnership's outstanding debt as of December 31, 2016 and 2015.

	December 31, 2016	December 31, 2015
	(In millions)	
Commercial Paper	$—	$236
Revolving Credit Facility	636	310
2015 Term Loan Agreement	450	450
Notes payable—affiliated companies (Note 14)	—	363
2019 Notes	500	500
2024 Notes	600	600
2044 Notes	550	550
EOIT Senior Notes	250	250
Premium (Discount) on long-term debt	17	23
Total debt	3,003	3,282
Less: Short-term debt[(1)]	—	236
Less: Unamortized debt expense	10	12
Less: Notes payable—affiliated companies	—	363
Total long-term debt	$2,993	$2,671

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(1) There were no commercial paper borrowings outstanding as of December 31, 2016. Short-term debt includes $236 million of commercial paper as of December 31, 2015.

Maturities of outstanding debt, excluding unamortized premiums, are as follows (in millions):

2017	$ —
2018	450
2019	500
2020	886
2021	—
Thereafter	1,150

Revolving Credit Facility

On June 18, 2015, the Partnership amended and restated its Revolving Credit Facility to, among other things, increase the borrowing capacity thereunder to $1.75 billion and extend its maturity date to June 18, 2020. As of December 31, 2016, there were $636 million of principal advances and $3 million in letters of credit outstanding under the Revolving Credit Facility. The weighted average interest rate of the Revolving Credit Facility was 2.21% as of December 31, 2016.

The Revolving Credit Facility provides that outstanding borrowings bear interest at LIBOR and/or an alternate base rate, at the Partnership's election, plus an applicable margin. The applicable margin is based on the Partnership's applicable credit ratings. As of December 31, 2016, the applicable margin for LIBOR-based borrowings under the Revolving Credit Facility was 1.50% based on the Partnership's credit ratings. In addition, the Revolving Credit Facility requires the Partnership to pay a fee on unused commitments. The commitment fee is based on the Partnership's applicable credit rating from the rating agencies. As of December 31, 2016, the commitment fee under the Revolving Credit Facility was 0.20% per annum based on the Partnership's credit ratings. The commitment fee is recorded as interest expense in the Partnership's Consolidated Statements of Income.

The Revolving Credit Facility contains a financial covenant requiring us to maintain a ratio of consolidated funded debt to consolidated EBITDA as defined under the Revolving Credit Facility as of the last day of each fiscal quarter of less than or equal to 5.00 to 1.00; provided that, for any three fiscal quarters including and following any fiscal quarter in which the aggregate value of one or more acquisitions by us or certain of our subsidiaries with a purchase price of at least $25 million in the aggregate, the consolidated funded debt to consolidated EBITDA ratio as of the last day of each such fiscal quarter during such period would be permitted to be up to 5.50 to 1.00.

The Revolving Credit Facility also contains covenants that restrict us and certain subsidiaries in respect of, among other things, mergers and consolidations, sales of all or substantially all assets, incurrence of subsidiary indebtedness, incurrence of liens, transactions with affiliates, designation of subsidiaries as Excluded Subsidiaries (as defined in the Revolving Credit Facility), restricted payments, changes in the nature of their respective businesses and entering into certain restrictive agreements. Borrowings under the Revolving Credit Facility are subject to acceleration upon the occurrence of certain defaults, including, among others, payment defaults on such facility, breach of representations, warranties and covenants, acceleration of indebtedness (other than intercompany and non-recourse indebtedness) of $100 million or more in the aggregate, change of control, nonpayment of uninsured money judgments in excess of $100 million and the occurrence of certain ERISA and bankruptcy events, subject where applicable to specified cure periods.

Commercial Paper

The Partnership has a commercial paper program pursuant to which the Partnership is authorized to issue up to $1.4 billion of commercial paper. The commercial paper program is supported by our Revolving Credit Facility, and outstanding commercial paper effectively reduces our borrowing capacity thereunder. There was zero and $236 million outstanding under our commercial paper program as of December 31, 2016 and 2015, respectively. On February 2, 2016, Standard & Poor’s Ratings Services lowered its credit rating on the Partnership from an investment grade rating to a non-investment grade rating. The short-term rating on the Partnership was also reduced from an investment grade rating to a non-investment grade rating. As a result of the downgrade, the Partnership repaid its outstanding borrowings under the commercial paper program upon maturity and did not issue any additional commercial paper.

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Term Loan Agreement

On July 31, 2015, the Partnership entered into a Term Loan Agreement dated as of July 31, 2015, providing for an unsecured three-year $450 million term loan agreement (2015 Term Loan Agreement). The entire $450 million principal amount of the 2015 Term Loan Agreement was borrowed by the Partnership on July 31, 2015. The 2015 Term Loan Agreement contains an option, which may be exercised up to two times, to extend the term of the 2015 Term Loan Agreement, in each case, for an additional one-year term. The 2015 Term Loan Agreement provides an option to prepay, without penalty or premium, the amount outstanding, or any portion thereof, in a minimum amount of $1 million, or any multiple of $0.5 million in excess thereof. As of December 31, 2016, there was $450 million outstanding under the 2015 Term Loan Agreement.

The 2015 Term Loan Agreement provides that outstanding borrowings bear interest at LIBOR and/or an alternate base rate, at the Partnership's election, plus an applicable margin. The applicable margin is based on our applicable credit ratings. As of December 31, 2016, the applicable margin for LIBOR-based borrowings under the 2015 Term Loan Agreement was 1.375% based on our credit ratings. As of December 31, 2016, the weighted average interest rate of the 2015 Term Loan Agreement was 1.86%.

The 2015 Term Loan Agreement contains substantially the same covenants as the Revolving Credit Facility.

Senior Notes

On May 27, 2014, the Partnership completed the private offering of $500 million 2.400% senior notes due 2019 (2019 Notes), $600 million 3.900% senior notes due 2024 (2024 Notes) and $550 million 5.000% senior notes due 2044 (2044 Notes), with registration rights. The Partnership received aggregate proceeds of $1.63 billion. Certain of the proceeds were used to repay the $1.05 billion senior unsecured 2013 Term Loan Agreement, the EOIT $250 million variable rate term loan, the EOIT $200 million 6.875% senior notes due July 15, 2014 and for general corporate purposes. On July 15, 2014, the Partnership repaid the EOIT $200 million 6.875% senior notes. A wholly owned subsidiary of CenterPoint Energy guaranteed collection of the Partnership's obligations under the 2019 Notes and 2024 Notes. The guarantee expired on May 1, 2016. The 2019 Notes, 2024 Notes and 2044 Notes have a $1 million unamortized discount and $10 million of unamortized debt expense at December 31, 2016, resulting in effective interest rates of 2.59%, 4.02% and 5.09%, respectively, during the year ended December 31, 2016.

In connection with the issuance of the 2019 Notes, 2024 Notes and 2044 Notes, the Partnership, CenterPoint Energy Resources Corp., as guarantor, and RBS Securities Inc., Merrill Lynch, Pierce, Fenner & Smith Incorporated, Credit Suisse Securities (USA) LLC, and RBC Capital Markets, LLC, as representatives of the initial purchasers, entered into a registration rights agreement whereby the Partnership and the guarantor agreed to file with the SEC a registration statement relating to a registered offer to exchange the 2019 Notes, 2024 Notes and 2044 Notes for new series of the Partnership's notes in the same aggregate principal amount as, and with terms substantially identical in all respects to, the 2019 Notes, 2024 Notes and 2044 Notes. The agreement provided for the accrual of additional interest if the Partnership did not complete an exchange offer by October 9, 2015. Because an exchange offer was not consummated by October 9, 2015, additional interest began accruing on the 2019 Notes, 2024 Notes and 2044 Notes on October 10, 2015, at a rate of 0.25% per year until the first 90-day period after such date. On December 29, 2015, the Partnership completed the exchange offer. As a result, the Partnership recognized approximately $1 million of additional interest expense during 2015.

The indenture governing the 2019 Notes, 2024 Notes and 2044 Notes contains certain restrictions, including, among others, limitations on our ability and the ability of our principal subsidiaries to: (i) consolidate or merge and sell all or substantially all of our and our subsidiaries' assets and properties; (ii) create, or permit to be created or to exist, any lien upon any of our or our principal subsidiaries' principal property, or upon any shares of stock of any principal subsidiary, to secure any debt; and (iii) enter into certain sale-leaseback transactions. These covenants are subject to certain exceptions and qualifications.

As of December 31, 2016, the Partnership's debt included EOIT's $250 million 6.25% senior notes due March 2020 (the EOIT Senior Notes). The EOIT Senior Notes have an $18 million unamortized premium at December 31, 2016, resulting in an effective interest rate of 3.83% during the year ended December 31, 2016. These senior notes do not contain any financial covenants other than a limitation on liens. This limitation on liens is subject to certain exceptions and qualifications.

Financing Costs

Unamortized debt expense of $15 million and $18 million at December 31, 2016 and 2015, respectively, is classified as either a reduction to Long-Term Debt or Other Assets in the Consolidated Balance Sheets and is being amortized over the life of the respective debt. Unamortized premium, net of unamortized discount on long-term debt of $17 million and $23 million at December 31, 2016 and 2015, respectively, is classified as either Long-Term Debt or Short-Term Debt, consistent with the underlying debt instrument, in the Consolidated Balance Sheets and is being amortized over the life of the respective debt.

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The Partnership recorded a $4 million loss on extinguishment of debt in the year ended December 31, 2014 associated with the retirement of the $1.05 billion 2013 Term Loan Agreement and the EOIT $250 million variable rate term loan, which is included in Other, net on the Consolidated Statements of Income.

As of December 31, 2016, the Partnership and EOIT were in compliance with all of their debt agreements, including financial covenants.

(11) Fair Value Measurements

Certain assets and liabilities are recorded at fair value in the Consolidated Balance Sheets and are categorized based upon the level of judgment associated with the inputs used to measure their value. Hierarchical levels, as defined below and directly related to the amount of subjectivity associated with the inputs to fair valuations of these assets and liabilities are as follows:

Level 1: Inputs are unadjusted quoted prices in active markets for identical assets or liabilities at the measurement date. Instruments classified as Level 1 include natural gas futures, swaps and options transactions for contracts traded on the NYMEX and settled through a NYMEX clearing broker.

Level 2: Inputs, other than quoted prices included in Level 1, are observable for the asset or liability, either directly or indirectly. Level 2 inputs include quoted prices for similar instruments in active markets, and inputs other than quoted prices that are observable for the asset or liability. Fair value assets and liabilities that are generally included in this category are derivatives with fair values based on inputs from actively quoted markets. Instruments classified as Level 2 include over-the-counter NYMEX natural gas swaps, natural gas basis swaps and natural gas purchase and sales transactions in markets such that the pricing is closely related to the NYMEX pricing, and over-the-counter WTI crude oil swaps for condensate sales.

Level 3: Inputs are unobservable for the asset or liability, and include situations where there is little, if any, market activity for the asset or liability. Unobservable inputs reflect the Partnership’s judgments about the assumptions market participants would use in pricing the asset or liability since limited market data exists. The Partnership develops these inputs based on the best information available, including the Partnership’s own data.

The Partnership utilizes the market approach in determining the fair value of its derivative positions by using either NYMEX or WTI published market prices, independent broker pricing data or broker/dealer valuations. The valuations of derivatives with pricing based on NYMEX published market prices may be considered Level 1 if they are settled through a NYMEX clearing broker account with daily margining. Over-the-counter derivatives with NYMEX or WTI based prices are considered Level 2 due to the impact of counterparty credit risk. Valuations based on independent broker pricing or broker/dealer valuations may be classified as Level 2 only to the extent they may be validated by an additional source of independent market data for an identical or closely related active market. In certain less liquid markets or for longer-term contracts, forward prices are not as readily available. In these circumstances, contracts are valued using internally developed methodologies that consider historical relationships among various quoted prices in active markets that result in management’s best estimate of fair value. These contracts are classified as Level 3.

The Partnership determines the appropriate level for each financial asset and liability on a quarterly basis and recognizes transfers between levels at the end of the reporting period. For the period ended December 31, 2016, there were no transfers between Level 2 and Level 3 instruments.

The impact to the fair value of derivatives due to credit risk is calculated using the probability of default based on Standard & Poor’s Ratings Services and/or internally generated ratings. The fair value of derivative assets is adjusted for credit risk. The fair value of derivative liabilities is adjusted for credit risk only if the impact is deemed material.

Estimated Fair Value of Financial Instruments

The fair values of all accounts receivable, notes receivable, accounts payable, commercial paper and other such financial instruments on the Consolidated Balance Sheets are estimated to be approximately equivalent to their carrying amounts and have been excluded from the table below. The following table summarizes the fair value and carrying amount of the Partnership’s financial instruments at December 31, 2016 and 2015:

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	December 31, 2016		December 31, 2015	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In millions)			
Long-Term Debt				
Long-term notes payable—affiliated companies (Level 2)	$ —	$ —	$ 363	$ 350
Revolving Credit Facility (Level 2)(1)	636	636	310	310
2015 Term Loan Agreement (Level 2)	450	450	450	450
EOIT Senior Notes (Level 2)	268	260	273	280
Enable Midstream Partners, LP, 2019, 2024 and 2044 Notes (Level 2)	1,649	1,521	1,650	1,255

(1) Borrowing capacity is effectively reduced by our borrowings outstanding under the commercial paper program. There was zero and $236 million of commercial paper outstanding as of December 31, 2016 and 2015, respectively.

The fair value of the Partnership's Long-term notes payable—affiliated companies, Revolving Credit Facility, and 2015 Term Loan Agreement, along with the EOIT Senior Notes and Enable Midstream Partners, LP, 2019, 2024 and 2044 Notes, is based on quoted market prices and estimates of current rates available for similar issues with similar maturities and is classified as Level 2 in the fair value hierarchy.

Non-Financial Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

Certain assets and liabilities are measured at fair value on a nonrecurring basis; that is, the assets and liabilities are not measured at fair value on an ongoing basis, but are subject to fair value adjustments in certain circumstances (e.g., when there is evidence of impairment).

During the years ended December 31, 2016, 2015 and 2014, the Partnership remeasured the Service Star assets at fair value. At December 31, 2016, 2015 and 2014, management reassessed the carrying value of the Service Star business line, a component of the gathering and processing segment that provides measurement and communication services to third parties. The 2016 impairment, which impaired substantially all of the remaining net book value of the Service Star business line, was primarily driven by the impact of planned technology changes affecting Service Star. The 2015 impairment was based upon higher than expected losses of customers and the 2014 impairment was due to decreases of crude oil and natural gas prices. Based on forecasted future undiscounted cash flows management determined that the carrying value of the Service Star assets were not fully recoverable. The Partnership utilized the income approach (generally accepted valuation approach) to estimate the fair value of these assets. The primary inputs are forecasted cash flows and the discount rate. The fair value measurement is based on inputs that are not observable in the market and thus represent level 3 inputs. Applying a discounted cash flow model to the property, plant and equipment and reviewing the associated materials and supplies inventory, during the years ended December 31, 2016, 2015 and 2014, the Partnership recognized a $9 million, $10 million and $7 million impairment, respectively. The $9 million consisted of an $8 million write-down of property, plant and equipment and a $1 million write-down of materials and supplies inventory considered either excess or obsolete. The $10 million impairment consisted of a $9 million write-down of property, plant and equipment and a $1 million write-down of materials and supplies inventory considered either excess or obsolete. The $7 million impairment consisted of write-downs of property, plant and equipment.

At December 31, 2015, due to decreases of crude oil and natural gas prices during 2015, management reassessed the carrying value of the Partnership's investment in the Atoka assets, a component of the gathering and processing segment. Based on forecasted future undiscounted cash flows, management determined that the carrying value of the Atoka assets were not fully recoverable. The Partnership utilized the income approach (generally accepted valuation approach) to estimate the fair value of these assets. The primary inputs are forecast cash flows and the discount rate. The fair value measurement is based on inputs that are not observable in the market and thus represent level 3 inputs. Applying a discounted cash flow model to the property, plant and equipment and intangible assets, the Partnership recognized a $25 million impairment during the year ended December 31, 2015. The $25 million impairment consisted of a $19 million write-down of property, plant and equipment and a $6 million write-down of intangible assets.

Additionally, during the year ended December 31, 2015, the Partnership recorded a $12 million impairment on jurisdictional pipelines in our transportation and storage segment.

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Contracts with Master Netting Arrangements

Fair value amounts recognized for forward, interest rate swap, option and other conditional or exchange contracts executed with the same counterparty under a master netting arrangement may be offset. The reporting entity's choice to offset or not must be applied consistently. A master netting arrangement exists if the reporting entity has multiple contracts, whether for the same type of conditional or exchange contract or for different types of contracts, with a single counterparty that are subject to a contractual agreement that provides for the net settlement of all contracts through a single payment in a single currency in the event of default on or termination of any one contract. Offsetting the fair values recognized for forward, interest rate swap, option and other conditional or exchange contracts outstanding with a single counterparty results in the net fair value of the transactions being reported as an asset or a liability in the Consolidated Balance Sheets. The Partnership has presented the fair values of its derivative contracts under master netting agreements using a net fair value presentation.

The following tables summarize the Partnership's assets and liabilities that are measured at fair value on a recurring basis as of December 31, 2016 and 2015:

December 31, 2016	Commodity Contracts		Gas Imbalances (1)	
	Assets	Liabilities	Assets (2)	Liabilities (3)
	(In millions)			
Quoted market prices in active market for identical assets (Level 1)	$2	$ 22	$ —	$ —
Significant other observable inputs (Level 2)	—	4	41	30
Unobservable inputs (Level 3)	—	8	—	—
Total fair value	2	34	41	30
Netting adjustments	—	—	—	—
Total	$2	$ 34	$ 41	$ 30

December 31, 2015	Commodity Contracts		Gas Imbalances (1)	
	Assets	Liabilities	Assets (2)	Liabilities (3)
	(In millions)			
Quoted market prices in active market for identical assets (Level 1)	$17	$ 3	$ —	$ —
Significant other observable inputs (Level 2)	10	—	17	20
Unobservable inputs (Level 3)	4	—	—	—
Total fair value	31	3	17	20
Netting adjustments	(3)	(3)	—	—
Total	$28	$ —	$ 17	$ 20

(1) The Partnership uses the market approach to fair value its gas imbalance assets and liabilities at individual, or where appropriate an average of, current market indices applicable to the Partnership's operations, not to exceed net realizable value. Gas imbalances held by EOIT are valued using an average of the Inside FERC Gas Market Report for Panhandle Eastern Pipe Line Co. (Texas, Oklahoma Mainline), ONEOK (Oklahoma) and ANR Pipeline (Oklahoma) indices. There were no netting adjustments as of December 31, 2016 and 2015.

(2) Gas imbalance assets exclude fuel reserves for under retained fuel due from shippers of zero and $6 million at December 31, 2016 and 2015, respectively, which fuel reserves are based on the value of natural gas at the time the imbalance was created and which are not subject to revaluation at fair market value.

(3)

Gas imbalance liabilities exclude fuel reserves for over retained fuel due to shippers of $5 million at each of December 31, 2016 and 2015, which fuel reserves are based on the value of natural gas at the time the imbalance was created and which are not subject to revaluation at fair market value.

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Changes in Level 3 Fair Value Measurements

The following tables provides a reconciliation of changes in the fair value of our Level 3 financial assets between the periods presented.

	Commodity Contracts	
	Crude oil (for condensate) financial futures/swaps	Natural gas liquids financial futures/swaps
	(In millions)	
Balance as of December 31, 2014	$ 5	$ —
Gains included in earnings	12	10
Settlements	(8)	(6)
Transfers out of Level 3[1]	(9)	—
Balance as of December 31, 2015	—	4
Losses included in earnings	—	(13)
Settlements	—	1
Transfers out of Level 3	—	—
Balance as of December 31, 2016	$ —	$ (8)

(1) The Partnership utilizes WTI crude oil swaps to manage exposure to condensate price risk. As the over-the-counter WTI crude oil swap is an active market, these derivative instruments were classified as Level 2 as of December 31, 2015.

Quantitative Information on Level 3 Fair Value Measurements

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

	December 31, 2016	
Product Group	Fair Value	Forward Curve Range
	(In millions)	(Per gallon)
Natural gas liquids	$(8)	$0.385 - $0.936

(12) Derivative Instruments and Hedging Activities

The Partnership is exposed to certain risks relating to its ongoing business operations. The primary risk managed using derivative instruments is commodity price risk. The Partnership is also exposed to credit risk in its business operations.

Commodity Price Risk

The Partnership has used forward physical contracts, commodity price swap contracts and commodity price option features to manage the Partnership's commodity price risk exposures in the past. Commodity derivative instruments used by the Partnership are as follows:

- NGL put options, NGL futures and swaps, and WTI crude oil futures and swaps for condensate sales are used to manage the Partnership's NGL and condensate exposure associated with its processing agreements;
- natural gas futures and swaps are used to manage the Partnership's natural gas exposure associated with its gathering, processing and transportation and storage assets; and
- natural gas futures and swaps, natural gas options and natural gas commodity purchases and sales are used to manage the Partnership's natural gas exposure associated with its storage and transportation contracts and asset management activities.

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Normal purchases and normal sales contracts are not recorded in Other Assets or Liabilities in the Consolidated Balance Sheets and earnings are recognized and recorded in the period in which physical delivery of the commodity occurs. Management applies normal purchases and normal sales treatment to: (i) commodity contracts for the purchase and sale of natural gas used in or produced by the Partnership’s operations and (ii) commodity contracts for the purchase and sale of NGLs produced by the Partnership’s gathering and processing business.

The Partnership recognizes its non-exchange traded derivative instruments as Other Assets or Liabilities in the Consolidated Balance Sheets at fair value with such amounts classified as current or long-term based on their anticipated settlement. Exchange traded transactions are settled on a net basis daily through margin accounts with a clearing broker and, therefore, are recorded at fair value on a net basis in Other Current Assets in the Consolidated Balance Sheets.

As of December 31, 2016 and 2015, the Partnership had no derivative instruments that were designated as cash flow or fair value hedges for accounting purposes.

Credit Risk

The Partnership is exposed to certain credit risks relating to its ongoing business operations. Credit risk includes the risk that counterparties that owe the Partnership money or energy will breach their obligations. If the counterparties to these arrangements fail to perform, the Partnership may seek or be forced to enter into alternative arrangements. In that event, the Partnership’s financial results could be adversely affected, and the Partnership could incur losses.

Derivatives Not Designated As Hedging Instruments

Derivative instruments not designated as hedging instruments for accounting purposes are utilized in the Partnership’s asset management activities. For derivative instruments not designated as hedging instruments, the gain or loss on the derivative is recognized currently in earnings.

Quantitative Disclosures Related to Derivative Instruments

The majority of natural gas physical purchases and sales not designated as hedges for accounting purposes are priced based on a monthly or daily index, and the fair value is subject to little or no market price risk. Natural gas physical sales volumes exceed natural gas physical purchase volumes due to the marketing of natural gas volumes purchased via the Partnership’s processing contracts, which are not derivative instruments.

As of December 31, 2016 and 2015, the Partnership had the following derivative instruments that were not designated as hedging instruments for accounting purposes:

	December 31, 2016		December 31, 2015	
	Gross Notional Volume			
	Purchases	Sales	Purchases	Sales
Natural gas—TBtu(1)				
Financial fixed futures/swaps	2	29	1	37
Financial basis futures/swaps	2	30	4	38
Physical purchases/sales	1	25	2	51
Crude oil (for condensate)—MBbl(2)				
Financial futures/swaps	—	540	—	506
Natural gas liquids—MBbl(3)				

Financial futures/swaps	60	1,133	75	1,011

(1) As of December 31, 2016, 100% of the natural gas contracts have durations of one year or less. As of December 31, 2015, 97.7% of the natural gas contracts had durations of one year or less and 2.3% had durations of more than one year and less than two years.

(2) As of December 31, 2016 and 2015, 100% of the crude oil (for condensate) contracts have durations of one year or less.

(3) As of December 31, 2016 and 2015, 100% of the natural gas liquid contracts have durations of one year or less.

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Balance Sheet Presentation Related to Derivative Instruments

The fair value of the derivative instruments that are presented in the Partnership's Consolidated Balance Sheet at December 31, 2016 and 2015 that were not designated as hedging instruments for accounting purposes are as follows:

		December 31, 2016		December 31, 2015	
		Fair Value			
Instrument	Balance Sheet Location	Assets	Liabilities	Assets	Liabilities
		(In millions)			
Natural gas					
Financial futures/swaps	Other Current	$2	$ 22	$ 17	$ 3
Physical purchases/sales	Other Current	—	1	1	—
Crude oil (for condensate)					
Financial futures/swaps	Other Current	—	3	9	—
Natural gas liquids					
Financial futures/swaps	Other Current	—	8	4	—
Total gross derivatives [(1)]		$2	$ 34	$ 31	$ 3

(1) See Note 11 for a reconciliation of the Partnership's total derivatives fair value to the Partnership's Consolidated Balance Sheets as of December 31, 2016 and 2015.

Income Statement Presentation Related to Derivative Instruments

The following table presents the effect of derivative instruments on the Partnership's Consolidated Statements of Income for the years ended December 31, 2016, 2015 and 2014:

	Amounts Recognized in Income		
	Year Ended December 31,		
	2016	2015	2014
	(In millions)		
Natural gas financial futures/swaps gains (losses)	$ (19)	$ 26	$ 37
Natural gas physical purchases/sales gains (losses)	(7)	(9)	1
Crude oil (for condensate) financial futures/swaps gains (losses)	(4)	12	9
Natural gas liquids financial futures/swaps gains (losses)	(13)	10	2
Total	$ (43)	$ 39	$ 49

For derivatives not designated as hedges in the tables above, amounts recognized in income for the years ended December 31, 2016, 2015 and 2014, if any, are reported in Product sales.

The following table presents the components of gain (loss) on derivative activity in the Partnership's Consolidated Statements of Income for the years ended December 31, 2016, 2015 and 2014:

	Year Ended December 31,		
	2016	2015	2014
	(In millions)		
Change in fair value of derivatives	$(60)	$(8)	$ 38

Realized gain on derivatives	17	47	11
Gain (loss) on derivative activity	$(43)	$39	$ 49

Credit-Risk Related Contingent Features in Derivative Instruments

Based upon the Partnership's senior unsecured debt rating with Moody's Investors Services or Standard & Poor's Ratings Services, the Partnership could be required to provide credit assurances to third parties, which could include letters of credit or cash collateral to satisfy its obligation under its financial and physical contracts relating to derivative instruments that are in a net

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liability position. As of December 31, 2016, under these obligations, $3 million of cash collateral has been posted. Based on positions as of December 31, 2016, there was no additional collateral required to be posted by the Partnership.

(13) Supplemental Disclosure of Cash Flow Information

The following table provides information regarding supplemental cash flow information:

	Year Ended December 31,		
	2016	2015	2014
	(In millions)		
Supplemental Disclosure of Cash Flow Information:			
Cash Payments:			
Interest, net of capitalized interest	$ 105	$ 85	$ 77
Income taxes, net of refunds	—	1	1
Non-cash transactions:			
Accounts payable related to capital expenditures	18	52	93
Issuance of common units upon interest acquisition of SESH (Note 9)	—	1	161

The following table reconciles cash and cash equivalents and restricted cash on the Consolidated Balance Sheets to cash, cash equivalents and restricted cash on the Consolidated Statement of Cash Flows:

	2016 (In millions)
Cash and cash equivalents	$ 6
Restricted cash	17
Cash, cash equivalents and restricted cash shown in the Consolidated Statement of Cash Flows	$ 23

(14) Related Party Transactions

The material related party transactions with CenterPoint Energy, OGE Energy and their respective subsidiaries are summarized below. There were no material related party transactions with other affiliates.

Transportation and Storage Agreements

Transportation and Storage Agreements with CenterPoint Energy

EGT provides the following services to CenterPoint Energy's LDCs in Arkansas, Louisiana, Oklahoma and Northeast Texas: (1) firm transportation with seasonal contract demand, (2) firm storage, (3) no notice transportation with associated storage and (4) maximum rate firm transportation. The first three services are in effect through March 31, 2021, and will remain in effect from year to year thereafter unless either party provides 180 days' written notice prior to the contract termination date. The maximum rate firm transportation is in effect through March 31, 2018. MRT provides firm transportation and firm storage services to CenterPoint Energy's LDCs under agreements that are in effect through May 15, 2018, but will continue year to year thereafter unless either party provides twelve months' written notice prior to the contract termination date.

In 2015, EGT relocated a portion of its pipeline in Arkansas to improve reliability and increase capacity by constructing an approximately 28.5 mile new pipeline segment and abandoning approximately 34.2 miles of existing pipelines segments. In connection with the project, EGT sold an approximately 12.4 mile pipeline segment to CenterPoint Energy’s Arkansas LDC for its remaining book value of $1 million, and EGT reimbursed CenterPoint Energy’s Arkansas LDC approximately $7 million dollars for cost incurred in connecting the LDC to EGT’s new pipeline segment.

Transportation and Storage Agreement with OGE Energy

EOIT provides no-notice load-following transportation and storage services to OGE Energy. On March 17, 2014, EOIT entered into a transportation agreement with OGE Energy, with a primary term of May 1, 2014 through April 30, 2019. Following the primary term, the agreement will remain in effect from year to year thereafter unless either party provides notice of termination to the other party at least 180 days prior to the commencement of the succeeding annual period.

On December 6, 2016, EOIT entered into a transportation agreement with OGE Energy, with a primary term expected to begin in late 2018 and extend for 20 years. In connection with the agreement, an approximately 80 mile pipeline will be built to serve OGE Energy's Muskogee Power Plant.

Gas Sales and Purchases Transactions

The Partnership sells natural gas volumes to affiliates of CenterPoint Energy and OGE Energy or purchase natural gas volumes from affiliates of CenterPoint Energy through a combination of forward, monthly and daily transactions. The Partnership enters into these physical natural gas transactions in the normal course of business based upon relevant market prices.

The Partnership's revenues from affiliated companies accounted for 7%, 7% and 6% of revenues during the years ended December 31, 2016, 2015 and 2014, respectively.

Amounts of revenues from affiliated companies included in the Partnership's Consolidated Statements of Income are summarized as follows:

	Year Ended December 31,		
	2016	2015	2014
	(In millions)		
Gas transportation and storage service revenue — CenterPoint Energy	$110	$110	$112
Natural gas product sales — CenterPoint Energy	1	7	22
Gas transportation and storage service revenue — OGE Energy	36	37	39
Natural gas product sales — OGE Energy	12	8	13
Total revenues — affiliated companies	$159	$162	$186

Amounts of natural gas purchased from affiliated companies included in the Partnership's Consolidated Statements of Income are summarized as follows:

	Year Ended December 31,		
	2016	2015	2014
	(In millions)		
Cost of natural gas purchases — CenterPoint Energy	$—	$ 2	$ 2
Cost of natural gas purchases — OGE Energy	14	15	19
Total cost of natural gas purchases — affiliated companies	$14	$ 17	$ 21

Corporate services and seconded employee expense

For the year ended December 31, 2014, the Partnership's employees were seconded by CenterPoint Energy and OGE Energy, and the Partnership reimbursed each of CenterPoint Energy and OGE Energy for all employee costs under the seconding agreements until the seconded employees transition from CenterPoint Energy and OGE Energy to the Partnership. The Partnership transitioned seconded employees from CenterPoint Energy and OGE Energy to the Partnership effective January 1, 2015, except for certain employees who are participants under OGE Energy's defined benefit and retiree medical plans, who will remain seconded to the Partnership, subject to certain termination rights of the Partnership and OGE Energy. The Partnership's reimbursement of OGE Energy for seconded employee costs arising out of OGE Energy's defined benefit and retiree medical plans is fixed at $6 million in 2016, $5 million in

2017, and at actual cost subject to a cap of $5 million in 2018 and thereafter, in the event of continued secondment.

Under the terms of the MFA, the Partnership receives services and support functions from each of CenterPoint Energy and OGE Energy under service agreements for an initial term that ended on April 30, 2016. The service agreements automatically extend year-to-year at the end of the initial term, unless terminated by the Partnership with at least 90 days' notice prior to the end of any extension. Additionally, the Partnership may terminate these service agreements at any time with 180 days' notice, if approved by the Board of Enable GP. The Partnership reimburses CenterPoint Energy and OGE Energy for these services up to annual caps, which for 2016 are $7 million and $6 million, respectively.

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On November 1, 2016, the Partnership entered into a new lease with an affiliate of CenterPoint Energy pursuant to which the Partnership leases office space in Shreveport, Louisiana. The term of the lease was effective on October 1, 2016 and extends through December 31, 2019. The Partnership expects to incur approximately $3 million in rent and maintenance expenses through the end of the initial term of the lease. Prior to October 1, 2016, CenterPoint Energy provided the office space in Shreveport, Louisiana under the services agreement. As of December 31, 2016, CenterPoint Energy continues to provide office and data center space to the Partnership in Houston, Texas under the services agreement.

Amounts charged to the Partnership by affiliates for seconded employees and corporate services, included primarily in Operation and maintenance expenses and General and administrative expenses in the Partnership's Consolidated Statements of Income are as follows:

	Year Ended December 31,		
	2016	2015	2014
	(In millions)		
Seconded Employee Costs - CenterPoint Energy	$—	$ —	$138
Corporate Services - CenterPoint Energy	6	15	29
Seconded Employee Costs - OGE Energy	29	35	105
Corporate Services - OGE Energy	5	11	17
Total corporate services and seconded employees expense	$40	$ 61	$289

Series A Preferred Units

On February 18, 2016, the Partnership completed the private placement of 14,520,000 Series A Preferred Units representing limited partner interests in the Partnership for a cash purchase price of $25.00 per Series A Preferred Unit, resulting in proceeds of $362 million, net of issuance costs. See Note 5 for further discussion of the Series A Preferred Units.

Notes payable

The Partnership had outstanding long-term notes payable—affiliated companies to CenterPoint Energy at December 31, 2015 of $363 million, which were scheduled to mature in 2017. On February 18, 2016, in connection with the private placement of the Series A Preferred Units, the Partnership redeemed the $363 million of notes payable—affiliated companies payable to a subsidiary of CenterPoint Energy.

The Partnership recorded affiliated interest expense to CenterPoint Energy on note payable—affiliated companies of $1 million, $8 million and $8 million during the years ended December 31, 2016, 2015 and 2014, respectively.

(15) Commitments and Contingencies

Operating Lease Obligations. The Partnership has operating lease obligations expiring at various dates. Future minimum payments for noncancellable operating leases are as follows:

	Year Ended December 31,						
	2017	2018	2019	2020	2021	After 2021	Total
	(In millions)						
Noncancellable operating leases	$10	$ 4	$ 3	$ —	$ —	$ —	$ 17

Total rental expense for all operating leases was $27 million, $32 million and $23 million during the years ended December 31, 2016, 2015 and 2014, respectively.

The Partnership currently occupies 162,053 square feet of office space at its executive offices under a lease that expires June 30, 2019. The lease payments are $19 million over the lease term, which began April 1, 2012. This lease has rent escalations which increase after 5 years, and will further escalate after 10 years if the lease is renewed. These lease expenses are included in General and administrative expense in the Consolidated Statements of Income.

The Partnership currently has 78 compression service agreements, of which 40 agreements are on a month-to-month basis,

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32 agreements will expire in 2017 and 6 agreements will expire in 2018. The Partnership also has 6 gas treating lease agreements, all of which are on a month-to-month basis. These lease expenses are reflected in Operation and maintenance expense in the Consolidated Statements of Income.

Legal, Regulatory and Other Matters

The Partnership is involved in legal, environmental, tax and regulatory proceedings before various courts, regulatory commissions and governmental agencies regarding matters arising in the ordinary course of business. Some of these proceedings involve substantial amounts. The Partnership regularly analyzes current information and, as necessary, provides accruals for probable liabilities on the eventual disposition of these matters. The Partnership does not expect the disposition of these matters to have a material adverse effect on its financial condition, results of operations or cash flows.

(16) Income Taxes

The Partnership's earnings are generally not subject to income tax (other than Texas state margin taxes and taxes associated with the Partnership's corporate subsidiaries, Enable Midstream Services and Enable Muskogee Intrastate Transmission) and are taxable at the individual partner level. The Partnership and its subsidiaries are pass-through entities for federal income tax purposes. For these entities, all income, expenses, gains, losses and tax credits generated flow through to their owners and, accordingly, do not result in a provision for income taxes in the consolidated financial statements. Consequently, the Consolidated Statements of Income do not include an income tax provision (other than Texas state margin taxes and taxes associated with the Partnership's corporate subsidiaries).

The items comprising income tax expense are as follows:

	Year Ended December 31,		
	2016	2015	2014
	(In millions)		
Provision (benefit) for current income taxes			
Federal	$(1)	$ —	$ —
State	—	1	1
Total provision (benefit) for current income taxes	(1)	1	1
Provision (benefit) for deferred income taxes, net			
Federal	$3	—	$ —
State	(1)	(1)	1
Total provision (benefit) for deferred income taxes, net	2	(1)	1
Total income tax expense	$1	$ —	$ 2

The following schedule reconciles the statutory Federal income tax rate to the effective income tax rate:

	Year Ended December 31,		
	2016	2015	2014
	(In millions)		
Income (loss) before income taxes	$314	$(771)	$535
Federal statutory rate	— %	— %	— %
Expected federal income tax expense	—	—	—
Increase in tax expense resulting from:			
State income taxes, net of federal income tax	1	—	2

Total	1	—	2
Total income tax expense	$1	$—	$2
Effective tax rate	0.3 %	— %	0.4 %

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The components of Deferred Income Taxes as of December 31, 2016 and 2015 were as follows:

	December 31,	
	2016	2015
	(In millions)	
Deferred tax assets:	$ —	$ —
Deferred tax liabilities:		
Non-current:		
Depreciation	7	9
Other	3	(1)
Total non-current deferred tax liabilities	10	8
Accumulated deferred income taxes, net	$ 10	$ 8

Uncertain Income Tax Positions

There were no unrecognized tax benefits as of December 31, 2016, 2015 and 2014.

Tax Audits and Settlements

The federal income tax return of the Partnership has been audited through the 2013 tax year.

(17) Equity Based Compensation

Enable GP has adopted the Enable Midstream Partners, LP Long Term Incentive Plan (LTIP) for officers, directors and employees of the Partnership and its affiliates, including any individual who provides services to the Partnership as a seconded employee. The long-term incentive plan provides for the following types of awards: restricted units, phantom units, appreciations rights, option rights, cash incentive awards, performance units, distribution equivalent rights, and other awards denominated in, payable in, valued in or otherwise based on or related to common units.

The long-term incentive plan is administered by the Compensation Committee of the Board of Directors. With respect to any grant of equity as long-term incentive awards to our independent directors and our officers subject to reporting under Section 16 of the Exchange Act, the Compensation Committee makes recommendations to the Board of Directors and any such awards will only be effective upon the approval of the Board of Directors. The long-term incentive plan limits the number of units that may be delivered pursuant to vested awards to 13,100,000 common units, subject to proportionate adjustment in the event of unit splits and similar events. Common units cancelled, forfeited, expired or cash settled are available for delivery pursuant to other awards.

The Board of Directors may terminate or amend the long-term incentive plan at any time with respect to any units for which a grant has not yet been made, including amending the long-term incentive plan to increase the number of units that may be granted subject to the requirements of the exchange upon which the common units are listed at that time. However, no change in any outstanding grant may be made that would be adverse to the participant without the consent of the participant.

The following table summarizes the Partnership's equity based compensation expense for the years ended December 31, 2016, 2015 and 2014 related to performance units, restricted units and phantom units for the Partnership's employees and independent directors:

	Year Ended December 31,

	2016	2015	2014
	(In millions)		
Performance units	$9	$ 3	$ 3
Restricted units	3	7	10
Phantom units	1	1	2
Total compensation expense	$13	$ 11	$ 15

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Performance Units

Awards of performance based phantom units (performance units) have been made under the LTIP in 2016, 2015 and 2014 to certain officers and employees providing services to the Partnership. Subject to the achievement of performance goals, the performance unit awards cliff vest three years from the grant date, with distribution equivalent rights paid at vesting. The performance goals for 2016, 2015 and 2014 awards are based on total unitholder return over a three calendar year performance cycle. Total unitholder return is based on the relative performance of the Partnership's common units against a peer group. The performance unit awards have a payout from 0% to 200% of the target based on the level of achievement of the performance goal. Performance units awards are paid out in common units, with distribution equivalent rights paid in cash at vesting. Any unearned performance units are cancelled. Pay out requires the confirmation of the achievement of the performance level by the Compensation Committee. Prior to vesting, performance units are subject to forfeiture if the recipient's employment with the Partnership is terminated for any reason other than death, disability, retirement or termination other than for cause within two years of a change in control. In the event of retirement, a participant will receive a pro rated payment based on the target performance, rather than actual performance, of the performance goals during the award cycle. Performance unit awards are classified as equity on the Partnership's Consolidated Balance Sheet.

The fair value of each performance unit award was estimated on the grant date using a lattice-based valuation model. The valuation information factored into the model includes the expected distribution yield, expected price volatility, risk-free interest rate and the probable outcome of the market condition over the expected life of the performance units. Compensation expense for each performance unit award is a fixed amount determined at the grant date fair value and is recognized over the three-year award cycle regardless of whether performance units are awarded at the end of the award cycle. Distributions are accumulated and paid at vesting and, therefore, are included in the fair value calculation of the performance unit award. Due to the short trading history of the Partnership's common units, the expected price volatility for the awards granted in 2016 is based on two years of daily stock price observations, combined with the average of the one-year volatility of the applicable peer group companies used to determine the total unitholder return ranking. The expected price volatility for the awards granted in 2015 is based on one year of daily stock price observations, combined with the average of the two-year volatility of the applicable peer group companies used to determine the total unitholder return ranking. The expected price volatility for the awards granted in 2014 is based on the average of the two-year volatility of the applicable peer group companies used to determine the total unitholder return ranking. The risk-free interest rate for the performance unit grants is based on the three-year U.S. Treasury yield curve in effect at the time of the grant. The expected life of the units is based on the non-vested period since inception of the award cycle. There are no post-vesting restrictions related to the Partnership's performance units. The number of performance units granted based on total unitholder return and the assumptions used to calculate the grant date fair value of the performance units based on total unitholder return are shown in the following table.

	2016	2015	2014
Number of units granted	1,235,429	501,474	563,963
Fair value of units granted	$10.42 - $27.77	$16.59	$29.61
Expected price volatility	43.2% - 46.0%	27.6 %	22.2 %
Risk-free interest rate	0.86% - 0.90%	0.99 %	0.83 %
Expected life of units (in years)	3.00	3.00	3.00

Phantom Units

Awards of phantom units have been made under the LTIP in 2016, 2015 and 2014 to certain officers and employees providing services to the Partnership and certain directors of Enable GP. In 2014, 100,000 phantom units were awarded to certain officers and employees providing services to the Partnership that vested on the first anniversary of the grant date with distribution equivalent rights paid at vesting. Also in 2014, 6,718 phantom units were awarded to the independent directors for their service as directors that vested on the first anniversary of the grant date with distribution equivalent rights paid during the vesting period. In 2015, 9,817 phantom units were granted to employees providing services to the Partnership that vest on the first, second or third anniversary of the grant date with distribution equivalent rights paid during the vesting period. In April 2016, 653,286 phantom units were awarded to certain officers and employees providing services to the Partnership that vest on the first, second or third anniversary of the award with distribution equivalent rights paid during the vesting period. Phantom units awards are paid out in common units, with distributions equivalent rights paid in cash. Phantom units cliff-vest at the end of the vesting period. Any unearned phantom units are cancelled. Prior to vesting, phantom units are subject to forfeiture if the recipient’s employment with the Partnership is terminated for any reason other than death, disability, retirement or termination other than for cause within two years of a change in control. Phantom unit awards are classified as equity on the Partnership’s Consolidated Balance Sheet.

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The fair value of the phantom units was based on the closing market price of the Partnership's common unit on the grant date. Compensation expense for the phantom unit is a fixed amount determined at the grant date fair value and is recognized as services are rendered by employees over the vesting period. Distributions on phantom units are either accumulated and paid at vesting or paid during the vesting period and, therefore, are included in the fair value calculation. The expected life of the phantom unit is based on the applicable vesting period. The number of phantom units granted and the grant date fair value are shown in the following table.

	2016	2015	2014
Phantom units granted	653,286	9,817	106,718
Fair value of phantom units granted	$8.12 - $15.30	$12.70	$23.16 - $23.70

Restricted Units

Awards of restricted units were made under the LTIP in 2015 and 2014 to certain officers and employees providing services to the Partnership and certain directors of Enable GP. These restricted unit awards cliff vest on the first, second, third or fourth anniversary of grant date, with distribution equivalent rights paid during the vesting period. Restricted units are outstanding and issued common units that cannot be sold, assigned, transferred or pledged by the recipient prior to vesting. Any unearned restricted units are cancelled. Prior to vesting, restricted units are subject to forfeiture if the recipient ceases to render substantial services to the Partnership for any reason other than death, disability, retirement or termination other than for cause within two years of a change in control.

In 2014, 375,000 restricted units were granted to Lynn Bourdon, who was then the Chief Executive Officer of Enable GP, of which 40% vested on August 1, 2014, 20% vested on February 1, 2015 and 40% vested on July 15, 2015; 150,000 restricted units to Mr. Bourdon, of which 50% vested on May 29, 2015 and 50% was forfeited upon his departure; 137,500 restricted units were granted to Rodney J. Sailor, who was then the Chief Financial Officer of Enable GP, of which 45.46% vested on March 1, 2015 and 54.54% vested on March 1, 2016; 25,000 restricted units were granted to Mr. Sailor, which vest four years from the grant date; and 304,901 restricted units were granted to officers and employees providing services to the Partnership which vest on the first, second, third or fourth anniversary of grant date. In 2015, 279,677 restricted units were granted to officers and employees providing services to the Partnership which vest on the first, second, or third anniversary of grant date. Prior to vesting, each share of restricted stock is subject to forfeiture if the recipient ceases to render substantial services to the Partnership for any reason other than death, disability or retirement. During the restriction period these units may not be sold, assigned, transferred or pledged and are subject to a risk of forfeiture. Restricted unit awards are classified as equity on the Partnership's Consolidated Balance Sheet.

The fair value of the restricted units was based on the closing market price of the Partnership's common unit on the grant date. Compensation expense for the restricted units is a fixed amount determined at the grant date fair value and is recognized as services are rendered by employees over a vesting period, as defined in the agreements. Distributions are paid as declared prior to vesting and, therefore, are included in the fair value calculation. After payment, distributions are not subject to forfeiture. The expected life of the restricted units is based on the non-vested period since inception of the award cycle.

The number of restricted units granted related to the Partnership's employees and the grant date fair value are shown in the following table.

	2015	2014
Restricted units granted on April 16, 2014 to the Chief Executive Officer and Chief Financial Officer of Enable GP	—	687,500
Fair value of restricted units granted	$ —	$ 22.60

Restricted units granted to the Partnership’s employees	279,677	304,901
Fair value of restricted units granted	$16.75 - $19.18	$23.56 - $25.50

Other Awards

In 2016 and 2015, the Board of Directors granted 14,914 and 17,384 common units, respectively, to the independent directors of Enable GP, for their service as directors, which vested immediately. The fair value of the common units were based on the closing market price of the Partnership’s common unit on the grant date.

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	2016	2015
Common units granted	14,914	17,384
Fair value of common units granted	$15.35	$11.12

Units Outstanding

A summary of the activity for the Partnership’s performance units, restricted units and phantom units as of December 31, 2016 and changes during 2016 are shown in the following table.

	Performance Units		Restricted Stock		Phantom Units	
	Number of Units	Weighted Average Grant-Date Fair Value, Per Unit	Number of Units	Weighted Average Grant-Date Fair Value, Per Unit	Number of Units	Weighted Average Grant-Date Fair Value, Per Unit
	(In millions, except unit data)					
Units Outstanding at 12/31/2015	814,510	$ 22.16	581,772	$ 21.04	9,817	$ 12.70
Granted[(1)]	1,235,429	10.80	—	—	653,286	8.45
Vested	(6,427)	20.77	(125,843)	22.78	(5,594)	12.44
Forfeited	(74,405)	15.94	(62,934)	19.43	(13,905)	8.12
Units Outstanding at 12/31/2016	1,969,107	15.27	392,995	20.74	643,604	8.49
Aggregate Intrinsic Value of Units Outstanding at 12/31/2016	$31		$6		$10	

(1) For performance units, this represents the target number of performance units granted. The actual number of performance units earned, if any, is dependent upon performance and may range from 0 percent to 200 percent of the target.

A summary of the Partnership’s performance, restricted and phantom units’ aggregate intrinsic value (market value at vesting date) and fair value of units vested (market value at date of grant) during the year ended December 31, 2016 are shown in the following table.

	December 31, 2016		
	Performance Units	Restricted Stock	Phantom Units
	(In millions)		
Aggregate Intrinsic Value of Units Vested	$ —	$ 1	$ —
Fair Value of Units Vested	—	3	—

Unrecognized Compensation Cost

A summary of the Partnership’s unrecognized compensation cost for its non-vested performance units, restricted units and phantom units, and the weighted-average periods over which the compensation cost is expected to be recognized are shown in the following table.

December 31, 2016	
Unrecognized Compensation Cost	Weighted Average to be Recognized (In years)

	(In millions)	
Performance Units	$15	1.81
Restricted Units	2	1.12
Phantom Units	4	2.20
Total	$21	

As of December 31, 2016, there were 9,307,350 units available for issuance under the long term incentive plan.

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(18) Reportable Segments

The Partnership’s determination of reportable segments considers the strategic operating units under which it manages sales, allocates resources and assesses performance of various products and services to wholesale or retail customers in differing regulatory environments. The accounting policies of the reportable segments are the same as those described in the summary of significant accounting policies described in Note 1. The Partnership uses operating income as the measure of profit or loss for its reportable segments.

The Partnership’s assets and operations are organized into two reportable segments: (i) gathering and processing, which primarily provides natural gas gathering, processing and fractionation services and crude oil gathering for our producer customers, and (ii) transportation and storage, which provides interstate and intrastate natural gas pipeline transportation and storage service primarily to natural gas producers, utilities and industrial customers.

Financial data for reportable segments are as follows:

Year Ended December 31, 2016	Gathering and Processing	Transportation and Storage [1]	Eliminations	Total
	(In millions)			
Product sales	$1,081	$ 479	$ (388)	$1,172
Service revenue	559	545	(4)	1,100
Total Revenues[2]	1,640	1,024	(392)	2,272
Cost of natural gas and natural gas liquids	915	492	(390)	1,017
Operation and maintenance, General and administrative	276	191	(2)	465
Depreciation and amortization	212	126	—	338
Impairments	9	—	—	9
Taxes other than income tax	32	26	—	58
Operating income	$196	$ 189	$ —	$385
Total assets	$7,453	$ 4,963	$ (1,204)	$11,212
Capital expenditures	$312	$ 71	$ —	$383

Year Ended December 31, 2015	Gathering and Processing	Transportation and Storage [1]	Eliminations	Total
	(In millions)			
Product sales	$1,118	$ 590	$ (374)	$1,334
Service revenue	545	542	(3)	1,084
Total Revenues[2]	1,663	1,132	(377)	2,418
Cost of natural gas and natural gas liquids	908	565	(376)	1,097
Operation and maintenance, General and administrative	293	230	(1)	522
Depreciation and amortization	195	123	—	318
Impairments	543	591	—	1,134
Taxes other than income tax	30	29	—	59
Operating loss	$(306)	$ (406)	$ —	$(712)
Total assets	$7,536	$ 4,976	$ (1,286)	$11,226
Capital expenditures	$839	$ 110	$ —	$949

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Year Ended December 31, 2014	Gathering and Processing	Transportation and Storage [1]	Eliminations	Total
	(In millions)			
Product sales	$1,907	$ 1,009	$ (616)	$2,300
Service revenue	517	568	(18)	1,067
Total Revenues[2]	2,424	1,577	(634)	3,367
Cost of natural gas and natural gas liquids	1,585	961	(632)	1,914
Operation and maintenance, General and administrative	297	232	(2)	527
Depreciation and amortization	160	116	—	276
Impairments	8	—	—	8
Taxes other than income tax	25	31	—	56
Operating income	$349	$ 237	$ —	$586
Total Assets	$8,356	$ 5,493	$ (2,012)	$11,837
Capital expenditures	$740	$ 103	$ (6)	$837

(1) Equity in earnings of equity method affiliate is included in Other Income (Expense) on the Consolidated Statements of Income, and is not included in the table above. See Note 9 for discussion regarding ownership interest in SESH and related equity earnings included in the transportation and storage segment for the years ended December 31, 2016, 2015 and 2014.

(2) The Partnership had no external customers accounting for 10% or more of revenues in periods shown. See Note 14 for revenues from affiliated companies.

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(19) Quarterly Financial Data (Unaudited)

Summarized unaudited quarterly financial data for 2016 and 2015 are as follows:

	Quarters Ended			
	March 31, 2016	June 30, 2016	September 30, 2016	December 31, 2016
	(in millions, except per unit data)			
Total Revenues	$509	$ 529	$ 620	$ 614
Cost of natural gas and natural gas liquids	195	254	268	300
Operating income	103	57	139	86
Net income	86	39	119	69
Net income attributable to limited partners	86	39	119	68
Net income attributable to common and subordinated units	86	35	110	59
Basic earnings per unit				
Common units	$0.21	$ 0.08	$ 0.26	$ 0.14
Subordinated units	$0.20	$ 0.08	$ 0.26	$ 0.14
Diluted earnings per unit				
Common units	$0.19	$ 0.08	$ 0.26	$ 0.14
Subordinated units	$0.20	$ 0.08	$ 0.26	$ 0.14

	Quarters Ended			
	March 31, 2015	June 30, 2015	September 30, 2015	December 31, 2015
	(in millions, except per unit data)			
Total Revenues	$616	$ 590	$ 646	$ 566
Cost of natural gas and natural gas liquids	292	277	287	241
Operating income (loss)[(1)]	104	93	(975)	66
Net income (loss)	91	77	(991)	52
Net income (loss) attributable to limited partners	91	77	(985)	65
Net income (loss) attributable to common and subordinated units	91	77	(985)	65
Basic earnings (loss) per unit				
Common Units	$0.22	$ 0.18	$ (2.33)	$ 0.15
Subordinated units	$0.21	$ 0.18	$ (2.34)	$ 0.15
Diluted earnings (loss) per unit				
Common Units	$0.22	$ 0.18	$ (2.33)	$ 0.15
Subordinated units	$0.21	$ 0.18	$ (2.34)	$ 0.15

(1) In the third quarter of 2015, the Partnership recorded a $1,087 million impairment to goodwill. For more information, see Note 8.

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

None.

Item 9A. Controls and Procedures

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Evaluation of Disclosure Controls and Procedures

Our management, with the participation of our chief executive officer and chief financial officer, has evaluated the effectiveness of our disclosure controls and procedures (as such term is defined in Rules 13a-15(e) or 15d-15(e) under the Securities Exchange Act of 1934, as amended (the “Exchange Act”)) as of December 31, 2016. Based on such evaluation, our management has concluded that, as of December 31, 2016, our disclosure controls and procedures are designed and effective to ensure that information required to be disclosed in our reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified by the SEC’s rules and forms and that information is accumulated and communicated to our management, including its principal executive officer and principal financial officer, or persons performing similar functions, as appropriate, to allow timely decisions regarding required disclosure.

In designing and evaluating our disclosure controls and procedures, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable, and not absolute, assurance that the objectives of the control system will be met. In addition, the design of any control system is based in part upon certain assumptions about the likelihood of future events and the application of judgment in evaluating the cost-benefit relationship of possible controls and procedures. Because of these and other inherent limitations of control systems, there is only reasonable assurance that our controls will succeed in achieving their goals under all potential future conditions.

Management’s Report on Internal Control Over Financial Reporting

Management of the Partnership is responsible for establishing and maintaining adequate internal control over financial reporting (as such term is defined in Exchange Act Rule 13a-15(f) or 15d-15(f)). The Partnership’s internal control over financial reporting is a process designed under the supervision and with the participation of our principal executive and principal financial officers, and effected by the board of directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the consolidated financial statements in accordance with generally accepted accounting principles.

The Partnership’s internal control over financial reporting includes policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the Partnership’s transactions and dispositions of the Partnership’s assets; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of the consolidated financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the Partnership are being made only in accordance with authorization of the Partnership’s management and directors; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the Partnership’s assets that could have a material effect on the consolidated financial statements.

Because of its inherent limitations, the Partnership’s 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 our policies or procedures may deteriorate.

Management assessed the effectiveness of the Partnership’s internal control over financial reporting as of December 31, 2016, with the participation of our principal executive and principal financial officers, based on the framework established in Internal Control—Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission, or COSO. Based on this assessment, management concluded that the Partnership maintained effective internal control over financial reporting as of December 31, 2016.

Our independently registered public accounting firm that audited our financial statements has issued an attestation report on the effectiveness of the Partnership's internal control over financial reporting. See Item 8. "Financial Statements and Supplementary Data."

Changes in Internal Controls

There were no changes in our internal controls over financial reporting during the quarter ended December 31, 2016, that have materially affected, or that are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information

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On February 16, 2017, OGE Energy notified the Board of Directors that OGE Energy has appointed Stephen E. Merrill to replace Peter B. Delaney as a director of the Board of Directors effective March 1, 2017. Mr. Merrill currently serves as Chief Financial Officer of OGE Energy and as an alternate director of the Board of Directors appointed by OGE Energy.

Neither the Enable GP nor the Partnership has entered into any material contract, plan or arrangement with, or will provide any compensation to, Mr. Merrill. There are no material arrangements or understandings between Mr. Merrill and any other person pursuant to which Mr. Merrill was appointed to serve as a director that are not described above. Mr. Merrill has not been appointed, and is not currently expected to be appointed, to any committee of the Board.

Part III

Item 10. Directors, Executive Officers and Corporate Governance

Management of the Partnership

As a limited partnership, we do not have directors or officers. Our operations and activities are managed by our general partner, Enable GP. Our general partner is not elected by our unitholders and will not be subject to re-election in the future. Our general partner is liable for all of our debts (to the extent not paid from our assets), except for indebtedness or other obligations that are made expressly non-recourse to it. Our general partner may therefore cause us to incur indebtedness or other obligations that are non-recourse to it.

The Board of Directors of our general partner oversees the management of our operations. The directors are appointed by CenterPoint Energy and OGE Energy, and our unitholders are not entitled to elect our directors or otherwise participate, directly or indirectly, in our management or operations. The Board of Directors is comprised of eight directors and one alternative director. CenterPoint Energy and OGE Energy have each appointed two of the directors, have jointly appointed three independent directors, and have jointly appointed our President and Chief Executive Officer as a director. The NYSE does not require us to have a majority of independent directors on the Board of Directors.

In identifying and evaluating both incumbent and new directors of the Board of Directors, CenterPoint Energy and OGE Energy assess their experience and personal characteristics against the following individual qualifications, which CenterPoint Energy and OGE Energy may modify from time to time:

- possesses appropriate skills and professional experience;
- has a reputation for integrity and other qualities;
- possesses expertise, including industry knowledge, determined in the context of the needs of the Board of Directors;
- has experience in positions with a high degree of responsibility;
- is a leader in the organizations with which he or she is affiliated;
- is diverse in terms of geography, gender, ethnicity and age;
- has the time, energy, interest and willingness to serve as a member of the Board of Directors; and
- meets such standards of independence and financial knowledge as may be required or desirable.

The officers of our general partner provide day-to-day management for our operations and activities. The officers of our general partner are appointed by the Board of Directors.

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The following table shows information regarding the current directors and executive officers of Enable GP. The business address of each of the directors and officers is listed below.

Name	Age	Title
Peter B. Delaney(1)	63	Director
Alan N. Harris(1)	63	Director
Ronnie K. Irani(1)	60	Director
Peter H. Kind(1)	60	Director
Stephen E. Merrill(2)	52	Alternate Director
Scott M. Prochazka(3)	51	Director and Chairman
William D. Rogers(3)	56	Director
Sean Trauschke(2)	49	Director
Paul M. Brewer(1)	58	Executive Vice President—Operations
Deanna J. Farmer(1)	51	Executive Vice President and Chief Administrative Officer
Craig Harris(1)	52	Executive Vice President and Chief Commercial Officer
John P. Laws(1)	42	Executive Vice President, Chief Financial Officer and Treasurer
Rodney J. Sailor(1)	58	Director, President and Chief Executive Officer
Mark C. Schroeder(3)	60	Executive Vice President and General Counsel

(1) One Leadership Square, 211 North Robinson Avenue, Suite 150, Oklahoma City, Oklahoma 73102
(2) 321 North Harvey, P.O. Box 321, Oklahoma City, Oklahoma 73101
(3) 1111 Louisiana Street, Houston, Texas 77002

Our directors hold office until the earlier of their death, resignation, removal or disqualification or until their successors have been elected and qualified. Officers serve at the discretion of the Board of Directors. There are no family relationships among any of our directors or executive officers.

Peter B. Delaney has been a Director of our general partner since May 2013 and served as interim President and Chief Executive Officer of our general partner from May 29, 2015 to December 31, 2015. Mr. Delaney is a member of the Board of Directors of OGE Energy. Previously, Mr. Delaney served as Chairman of OGE Energy and OG&E until November 30, 2015; as Chairman and Chief Executive Officer of OGE Energy and OG&E from July 2013 to May 29, 2015; as Chairman, President and Chief Executive Officer of OGE Energy and OG&E from December 2011 to July 2013; as Chairman and Chief Executive Officer of OGE Energy and OG&E from January 2011 to December 2011; as Chairman, President and Chief Executive Officer of OGE Energy and OG&E from September 2007 to December 2010; and as the Chief Executive Officer of Enogex Holdings and Chief Executive Officer of Enogex from 2010 to 2013. Mr. Delaney has been a member of the Board of Directors of the Federal Reserve Bank of Kansas City Oklahoma City Branch since January 2012, and Mr. Delaney has served as Chairman of the Federal Reserve Bank of Kansas City Oklahoma City branch since January 2015. Mr. Delaney was a director of OGE Energy and OG&E from January 2007 through March 2016. We believe Mr. Delaney's extensive knowledge of the industry and us, our operations and people, gained with OGE Energy and its affiliates in positions of increasing responsibility provides the Board with valuable experience.

Alan N. Harris has been a Director of our general partner since February 2015. Mr. Harris retired from Spectra Energy Corp in January 2015. Mr. Harris joined Spectra Energy Corp. in 1982 and served in multiple roles with increasing responsibilities. Most recently, he served as Senior Advisor to the Chairman, President and Chief Executive Officer of Spectra Energy Corp. In his role, Mr. Harris provided oversight and focus for Spectra Energy Corp's project execution efforts. From 2009 through 2013, Mr. Harris served as Chief Development and Operations Officer of Spectra Energy Corp. In that dual role, Mr. Harris oversaw the company's strategy, business development, and mergers and acquisitions, as well as project execution, the operations of Spectra Energy Corp's U.S. pipeline and storage business, environment, health and safety, and the company's master limited partnership. Mr. Harris served as Chief

Development Officer of Spectra Energy Corp from 2007 to 2009 and has served as a member of the Board of Directors of the general partner of DCP Midstream Partners, LP from January 2014 through October 2014 and from January 2009 through April 2012. We believe that Mr. Harris' extensive knowledge of the industry provides the Board with valuable experience.

Ronnie K. Irani has been a Director of our general partner since March 2016. Mr. Irani is President and Chief Executive Officer of RKI Energy Resources, LLC and NewWoods Petroleum, LLC, which are oil and gas exploration and production companies. Prior to forming RKI Energy Resources in October 2015 and NewWoods Petroleum, LLC in August 2015, Mr. Irani served as President and Chief Executive Officer of RKI Exploration & Production, LLC from 2005 until its acquisition by WPX Energy, Inc. in August 2015. Prior to forming RKI Exploration & Production, Mr. Irani served in executive positions at Dominion Resources, Inc., Louis Dreyfus Natural Gas Corp. and Woods Petroleum Corporation. Mr. Irani also served as a Director of Seventy Seven Energy, Inc. from June 2014 through August 2016. Seventy Seven Energy filed for reorganization under Chapter 11 of the United States Bankruptcy Code in June 2016. We believe that Mr. Irani's extensive experience in exploration and production provides the Board with valuable insight.

Peter H. Kind has been a Director of our general partner since February 2014. Mr. Kind is Executive Director of Energy Infrastructure Advocates LLC, an independent financial and strategic advisory firm. Previously, Mr. Kind was a Senior Managing Director of Macquarie Capital, an investment banking firm from 2009 to 2011 and a Managing Director of Bank of America Securities from 2005 to 2009. Mr. Kind is a director of Southwest Water Company, a privately held company, where he is chairman of the audit committee, and a director of the general partner of NextEra Energy Partners, LP, where he is an audit committee member and chairman of the conflicts committee. We believe Mr. Kind, with more than 30 years of experience providing corporate and investment banking services to the utility and energy industries, provides the Board with valuable experience in financial and capital markets matters. Mr. Kind, a Certified Public Accountant, also has experience in the audit of large public energy companies.

Stephen E. Merrill has been an alternate Director of our general partner since May 2015. Mr. Merrill is Chief Financial Officer of OGE Energy and OG&E. Previously, Mr. Merrill served as Executive Vice President and Chief Administrative Officer of our general partner from April 2014 to August 2014; as Executive Vice President of Finance and Chief Administrative Officer of our general partner from December 2013 to April 2014; Chief Operating Officer of Enogex from 2011 through April 2014; Vice President-Human Resources of OGE Energy from 2009 to 2011; and Vice President and Chief Financial Officer of Enogex from 2008 to 2011. We believe Mr. Merrill's energy industry provides the Board with valuable experience in overseeing the management of our operation and financial experience provides the Board with valuable experience in our financial and accounting matters.

Scott M. Prochazka has been a Director of our general partner since November 2013 and has served as Chairman of the Board of our general partner since May 29, 2015. Mr. Prochazka is President and Chief Executive Officer of CenterPoint Energy. Previously, Mr. Prochazka served as Executive Vice President and Chief Operating Officer from August 2012 to December 2013; Senior Vice President and Division President, Electric Operations of CenterPoint Energy from May 2011 to July 2012; and as Division Senior Vice President, Electric Operations of CenterPoint Energy's wholly owned subsidiary, CenterPoint Energy Houston Electric, LLC, from February 2009 to May 2011. Mr. Prochazka has served as a director of CenterPoint Energy since November 2013. We believe Mr. Prochazka's extensive knowledge of the industry and us, our operations and people, gained in his years of service with CenterPoint Energy in positions of increasing responsibility provides the Board with valuable experience.

William D. Rogers has been a Director of our general partner since August 2015 and previously served as an alternate Director of our general partner from May 2015 through July 2015. Mr. Rogers is Executive Vice President and Chief Financial Officer of CenterPoint Energy. Previously, Mr. Rogers served as Executive Vice President, Finance and Accounting of CenterPoint Energy from February 2015 through March 2015; Vice President and Treasurer of American Water Works Company, Inc. from October 2010 to January 2015; and Chief Financial Officer of NV Energy, Inc. from February 2007 through February 2010. We believe Mr. Roger's financial experience provides the Board with valuable experience in our financial and accounting matters.

Sean Trauschke has been a Director of our general partner since May 2013. From May 2013 to December 2013, he served as Acting Chief Financial Officer of our general partner. Mr. Trauschke is Chairman, President and Chief Executive Officer of OGE Energy and OG&E. Previously, Mr. Trauschke served as President and Chief Executive

Officer of OGE Energy and OG&E from May 29, 2015 to November 30, 2015; as President of OGE Energy and OG&E from September 2014 to May 29, 2015; as Vice President and Chief Financial Officer of OGE Energy from 2009 to September 2014; Vice President and Chief Financial Officer of OG&E from 2009 to July 2013; Chief Financial Officer of Enogex Holdings from 2010 to 2013; Chief Financial Officer of Enogex LLC from 2009 to 2013; and Senior Vice President-Investor Relations and Financial Planning of Duke Energy from 2008 to 2009. We believe Mr. Trauschke’s energy industry and financial experience provides the Board with valuable experience in our financial and accounting matters.

Paul M. Brewer has served as Executive Vice President—Operations of our general partner since January 2016. Previously, Mr. Brewer served as Senior Vice President—Field Operations and Environmental, Health & Safety of our general partner from February 2014 to January 2016; Senior Vice President Field Operations and Engineering & Construction of our general partner from December 2013 to February 2014; Senior Vice President Environmental, Health & Safety and Compliance Services of our general partner from October 2013 to December 2013; Senior Vice President—Project Management Office from July 2013 to October 2013; Vice President of Operations of our general partner from May 2013 to July 2013; and Vice President of Operations of Enogex from July 2008 to May 2013. Earlier in his career, Mr. Brewer spent 12 years with DCP Midstream and its predecessor companies and over 13 years with Mobil Oil and its predecessor companies.

Deanna J. Farmer has served as Executive Vice President and Chief Administrative Officer of our general partner since September 2014. Previously, Ms. Farmer served as Vice President of Corporate Services and Chief Information Officer of the general partner of Access Midstream Partners, LP from June 2014 to September 2014; Vice President of Corporate Services and Human Resources of the general partner of Access Midstream Partners, LP from September 2012 to June 2014; Director of Finance and Information Management of the general partner of Chesapeake Midstream Partners, LP from February 2010 to September 2012; and Director of Information Technology of Chesapeake Energy, Inc. from 2005 to February 2010.

Craig Harris has served as Executive Vice President and Chief Commercial Officer of our general partner since September 2016. Previously, Mr. Harris served as Senior Vice President-Business Development and Marketing of Columbia Midstream Group from July 2015 through July 2016 and as Vice President-Business Development of Columbia Midstream Group from November 2013 through July 2015. Columbia Midstream Group is a unit of Columbia Pipeline Group, Inc., which became a wholly-owned subsidiary of TransCanada Corporation in July 2016. Prior to joining Columbia Midstream Group, Mr. Harris served as Managing Director of Alinda Capital Partners, LLC, an infrastructure investment firm, from February 2011 through November 2013.

John P. Laws has served as Executive Vice President and Chief Financial Officer of our general partner since January 2016 and as Treasurer of our general partner since December 2013. Previously, Mr. Laws served as Vice President of our general partner from April 2014 to January 2016; as Vice President of Planning and Development of Enable Oklahoma Intrastate Transmission, LLC from May 2013 to December 2013; as Vice President of Planning and Development of Enogex Holdings, LLC from November 2011 to May 2013; and as Managing Director of Finance of Enogex, LLC from January 2010 through November 2011.

Rodney J. Sailor has served as a Director and as President and Chief Executive Officer of our general partner since January 1, 2016. Previously, Mr. Sailor served as Chief Financial Officer of our general partner from March 2014 to December 2015 and Executive Vice President of our general partner from April 2014 to December 2015; Senior Vice President and Chief Financial Officer of WPX Energy, Inc. from December 2011 to March 2014; and as Vice President and Treasurer of the Williams Companies, Inc. from 2005 to 2011. Prior to 2005, Mr. Sailor served in various capacities, including finance, accounting and business development roles for The Williams Companies, Inc. Mr. Sailor served as a Director of Williams Partners GP LLC, the general partner of Williams Partners L.P., from October 2007 to 2010; served as a director of Apco Oil and Gas International Inc. from September 2006 to March 2014; and as Chief Financial Officer of Apco from December 2012 to March 2014. We believe Mr. Sailor’s energy industry and financial experience provides the Board with valuable experience in overseeing the management of our operations.

Mark C. Schroeder has served as the General Counsel of our general partner since July 2013 and as Executive Vice President of our general partner since April 2014. Previously, Mr. Schroeder served as Senior Vice President and Deputy General Counsel of CenterPoint Energy from July 2011 to February 2014; and Vice President and General Counsel-Midstream of CenterPoint Energy from August 2003 to July 2011.

Board of Directors

Chairmanship

Scott M. Prochazka has served as chairman of the Board of Directors since May 29, 2015. Mr. Prochazka’s term will expire on May 29, 2017, at which time OGE Energy will have the right to appoint the next chairman. Under the limited liability company agreement of our general partner, the right to appoint the chairman of the Board of Directors will rotate between CenterPoint Energy and OGE Energy every two years. Although the Board of Directors has no policy with respect to the separation of the offices of chairman of the board and chief executive officer, we do not expect these positions to be occupied by the same individual due to the rotating chairmanship provision in the general partner's limited liability company agreement.

Board Membership

Members of the Board of Directors are appointed by CenterPoint Energy and OGE Energy. Accordingly, unlike holders of common stock in a corporation, our unitholders have only limited voting rights on matters affecting our business or governance, subject in all cases to any specific unitholder rights contained in our partnership agreement. CenterPoint Energy and OGE Energy are each entitled to appoint two directors and up to two alternate directors. Directors Scott M. Prochazka and Williams D. Rogers were appointed by CenterPoint Energy. Directors Peter B. Delaney and Sean Trauschke, as well as alternate director Stephen E. Merrill, were appointed by OGE Energy. Alternate directors are entitled to receive notice of and attend meetings of the Board of Directors as an observer, unless they are serving in place of a director designated by the party who appointed them. Alternate directors, in the sole discretion of the party appointing them, can serve in place of a Director designated by the party who appointed them at any meeting of the Board of Directors or in connection with any action or approval by the Board of Directors. Each independent director, who is required to meet the independence standards for audit committee members established by the NYSE and the Exchange Act, and any other directors are appointed by the unanimous agreement of CenterPoint Energy and OGE Energy. Directors Alan N. Harris, Ronnie K. Irani, and Peter H. Kind are independent directors.

Board Role in Risk Oversight

Our governance guidelines provide that the Board of Directors is responsible for reviewing the process for assessing the major risks facing us and the options for their mitigation. This responsibility is largely satisfied by the audit committee, which is responsible for reviewing and discussing with management and our registered public accounting firm our major risk exposures and the policies management has implemented to monitor such exposures, including our financial risk exposures and risk management policies.

Committees of the Board of Directors

Audit Committee. Peter H. Kind, Alan N. Harris and Ronnie K. Irani serve as the members of the audit committee. Mr. Kind is the current chairman of the audit committee. The Board of Directors is required to have an audit committee of at least three members who meet the independence and experience standards established by the NYSE and the Exchange Act. All of our members of the audit committee meet these independence and experience standards. In addition, Mr. Kind and Mr. Harris meet the Exchange Act definition of an audit committee financial expert. The audit committee assists the Board of Directors in its oversight of the integrity of our financial statements and our compliance with legal and regulatory requirements and corporate policies and controls. The audit committee has the sole authority to retain and terminate our independent registered public accounting firm, approve all auditing services and related fees and the terms thereof and pre-approve any non-audit services to be rendered by our independent registered public accounting firm. The audit committee is also responsible for confirming the independence and objectivity of our independent registered public accounting firm. Our independent registered public accounting firm has been given unrestricted access to the audit committee.

Conflicts Committee. Peter H. Kind, Alan N. Harris and Ronnie K. Irani serve as the members of the conflicts committee. Mr. Kind is the current chairman of the conflicts committee. The members of our conflicts committee may not be officers or employees of our general partner or directors, officers or employees of its affiliates, may not hold an ownership interest in our general partner or its affiliates other than common units or awards under any long-term incentive plan, equity compensation plan, or similar plan implemented by our general partner or the Partnership, and must meet the independence and experience standards established by the NYSE and the Exchange Act for audit committee members. All of the members of the conflicts committee meet these standards. The conflicts committee determines if the resolution of any conflict of interest referred to it by our general partner is in our best interests. There is no requirement that our general partner seek the approval of the conflicts committee for the resolution of any conflict. Any matters approved by the conflicts committee in good faith are deemed to be approved by all of our partners and not a breach by our general partner of any duties it may owe us or our unitholders. Any unitholder challenging any matter approved by the conflicts committee has the burden of proving that the members of the conflicts committee did not believe that the matter was in the best interests of the Partnership. Moreover, any acts taken or omitted to be taken in reliance upon the advice or opinions of experts such as legal counsel, accountants, appraisers, management consultants and investment bankers, where our general partner (or any members of the Board of Directors including any member of the conflicts committee) reasonably believes the advice or opinion to be within such person’s professional or expert competence, are conclusively presumed to have been done or omitted in good faith.

Compensation Committee. Alan N. Harris, Scott M. Prochazka and Sean Trauschke serve as the members of the compensation committee. The members of our compensation committee are not required to meet the independence standards established by the NYSE for compensation committee members. Mr. Harris is the current chairman of the compensation committee. The Board of Directors has delegated responsibility and authority to the board's Compensation Committee for the compensation of our named executive officers and independent directors. For more information on the role of the Compensation Committee and compensation program for our named executive officers and independent directors, see Item 11. "Executive Compensation".

Governance Guidelines

We have adopted Governance Guidelines to assist the Board in the exercise of its responsibilities. To promote open discussion among the non-management directors of our Board and among the independent directors of our Board, our Governance Guidelines provide that the non-management directors will meet separately in executive session periodically and that the independent directors will meet separately in executive session at least once a year. Currently, the chairman of the Board of Directors presides at the executive sessions of the non-management directors and the chairman of the audit committee presides at the executive sessions

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of the independent directors. The Partnership's definitions of independence are provided in the Partnership's Governance Guidelines, which are available under the "Governance" subsection of the "Investors" section of our website at www.enablemidstream.com.

Communications with the Board

Unitholders and other interested parties that wish to communicate with members of our Board of Directors, including the Chairman of the Board, the non-management directors individually or as a group, or the independent directors individually or as a group, may send correspondence to them in care of the General Counsel by mail to PO Box 24300, Oklahoma City, Oklahoma 73124-0300 or by email to gc@enablemidstream.com.

Compliance with Section 16(a) of the Exchange Act

Section 16(a) of the Exchange Act requires our directors, certain officers, persons who own more than 10 percent of a registered class of our equity securities to file reports with the SEC concerning their holdings of, and certain transactions in, our equity and derivative securities (e.g., options, convertible securities and other securities that derive their value from equity securities). Based solely upon our review of copies of filings from reporting persons, we do not believe that any of our directors or officers or any persons who own more than 10 percent of a registered class of our equity securities failed to file on a timely basis all of the report required under Section 16(a) of the Exchange Act, except as follows: Peter B. Delaney, director, inadvertently failed to timely report an acquisition of 2,000 common units.

Code of Ethics

Our general partner has adopted a Code of Business Conduct and Ethics that applies to the directors, officers of our general partner, the Partnership, and our subsidiaries. Our general partner has also adopted a Code of Ethics for Senior Financial Officers that applies to our chief executive officer, chief financial officer, chief accounting officer, treasurer and other persons performing similar functions. We make available free of charge our Code of Business Conduct and Ethics, and Code of Ethics for Senior Financial Officers, as well as our Governance Guidelines, related party transactions policy, audit committee charter, compensation committee charter and insider trading policy under the "Governance" subsection of the "Investors" section of our website at www.enablemidstream.com.

Item 11. Executive Compensation

Compensation Discussion and Analysis

Overview

In this section, we describe and discuss the principles and policies used in setting the compensation of our named executive officers. Our named executive officers for the fiscal year ended December 31, 2016 are Deanna J. Farmer, Executive Vice President and Chief Administrative Officer, Craig Harris, Executive Vice President and Chief Commercial Officer, John P. Laws, Executive Vice President, Chief Financial Officer, and Treasurer, Rodney J. Sailor, President and Chief Executive Officer and Mark C. Schroeder, Executive Vice President and General Counsel.

Objective and Design of Executive Compensation Program

We strive to provide compensation that is competitive, both on a total level and in individual components, both with our peers and with other likely competitors for executive talent. By competitive, we mean that total compensation and each element of compensation is within what we believe to be an appropriate range of the market level of compensation for similarly situated roles.

Our Compensation Committee bases compensation decisions on principles designed to align the interests of our named executive officers with those of our unitholders. Our overall compensation philosophy is pay for performance. We seek to motivate our named executive officers to achieve individual and business performance objectives by designing their compensation packages to align with our values, strategy, and financial results. We believe that our named executive officers should be rewarded for both the short-term and long-term success of the Partnership and, conversely, be subject to a degree of downside risk in the event that the Partnership does not achieve its performance objectives. As a result, actual compensation in a given year will vary based on

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our performance, and to a lesser extent, on qualitative appraisals of individual performance. We design the compensation packages for our named executive officers to have a significant percentage of their total compensation at risk, thus aligning each of our named executive officers with the short-term and long-term performance objectives of the Partnership and with the interests of our unitholders.

We maintain benefit programs for our employees, including our named executive officers, with the objective of retaining their services. Our benefits reflect competitive practices at the time the benefit programs were implemented and, in some cases, reflect our desire to maintain similar benefits treatment for all employees in similar positions. To the extent possible, we structure these programs to deliver benefits in a manner that is tax efficient to both the recipient and the Partnership. The Compensation Committee intends for its compensation design principles to protect and promote our unitholders' interests. We believe our compensation programs are consistent with best practices for sound governance.

Our Executive Compensation Program. The Compensation Committee of our Board of Directors oversees the compensation of our named executive officers, including base salary and short-term and long-term incentive awards. In addition, the Compensation Committee makes any remaining determinations with respect to compensation based upon the previous year's performance. With respect to any grant of equity as long-term incentive awards to our named executive officers, the Compensation Committee makes recommendations to the Board of Directors, but any such equity grants require the approval of the Board of Directors.

Role of Consultant. To provide advice on the form and amount of compensation for our named executive officers in 2016 and 2017, our Compensation Committee engaged Mercer (US) Inc. ("Mercer"), an independent compensation consulting firm. Mercer's services included a compensation risk assessment and an analysis of 2016 base salaries, short-term incentive award targets, and long-term incentive award targets. In order to assist with the assessment of the competitiveness of our 2016 named executive officer compensation, Mercer provided market data from the following peer group companies:

Boardwalk Pipeline Partners, LP	MarkWest Energy, Partners LP
Buckeye Partners LP	NuStar Energy LP
DCP Midstream Partners, LP	ONEOK Partners, LP
Enbridge Energy Partners, LP	Spectra Energy Partners, LP
EnLink Midstream Partners, LP	Targa Resources Partners LP
Magellan Midstream Partners, LP	Western Gas Partners, LP

Due to changes in the energy industry, Mercer provided market data for our 2017 named executive officer compensation from the following peer group companies:

Boardwalk Pipeline Partners, LP	NuStar Energy LP
Buckeye Partners LP	Spectra Energy Partners, LP
Crestwood Equity Partners, LP	Summit Midstream Partners, LP
DCP Midstream Partners, LP	SemGroup Corp.
EnLink Midstream Partners, LP	Targa Resources Corp.
Magellan Midstream Partners, LP	Western Gas Partners, LP
ONEOK Partners, LP	Williams Partners LP
MPLX LP	

The Compensation Committee reviews and assesses the independence and performance of its consultant in accordance with applicable SEC and NYSE rules on an annual basis in order to confirm that the consultant is independent and meets all applicable regulatory requirements. Prior to its engagement for 2016 and 2017, the Compensation

Committee reviewed the independence of Mercer and determined that it meets all applicable regulatory requirements for independence.

Role of Executive Officers. Of our named executive officers, our Chief Executive Officer and our Chief Administrative Officer have roles in determining executive compensation policies and programs. Our Chief Executive Officer and our Chief Administrative Officer work with business unit and functional leaders along with our internal compensation staff to provide information to the Board of Directors and the Compensation Committee to help ensure that our compensation programs support

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our business strategy and goals. Our Chief Executive Officer also makes preliminary recommendations for base salary adjustments and short-term and long-term incentive levels for the named executive officers other than himself.

Our Chief Executive Officer and our Chief Administrative Officer also periodically review and recommend specific Partnership performance metrics to be used in awards under our short-term and long-term incentive plans. Our Chief Executive Officer and our Chief Administrative Officer work with the various business units and functional departments to develop these metrics, which are then presented to the Compensation Committee. As noted above, the Compensation Committee makes recommendations to the Board of Directors for awards to our named executive officers under our long-term incentive plan, but any such equity grants require the approval of the Board of Directors.

Elements of Compensation

The total annual direct compensation program for our named executive officers consists of three components: (1) base salary; (2) a short-term cash incentive, which is based on a percentage of annual base salary; and (3) equity based grants under our long-term incentive plan, which are based on a percentage of annual base salary. Under our compensation structure, the allocation between base salary, short-term incentive and long-term incentive varies depending upon job title and responsibility levels. We consider it generally appropriate for officers with more responsibility to have a larger portion of their compensation at risk.

Base Salary. We view base salary as the foundation of total compensation. Base salary recognizes the job being performed and the value of that job in the competitive market. We design base salaries to attract and retain the executive talent necessary for our continued success and provide an element of compensation that is not at risk in order to avoid fluctuations in compensation that could distract our named executive officers from the performance of their responsibilities. Any annual adjustments to the base salaries of our named executive officers are primarily intended to reflect either changes or responses to changes in market data or increased experience and individual contribution of the executive. We set and adjust base salaries using market data from the Compensation Committee’s consultant, and we target a range of 80% to 120% of the market median for each position.

Short-Term Incentives. We adopted the Enable Midstream Partners, LP Short-Term Incentive Plan for our officers and employees. Under our short-term incentive plan, we seek to encourage a high level of performance from our named executive officers through the establishment of predetermined Partnership goals, the attainment of which will require a high degree of competence and diligence on the part of those employees selected to participate, and which will be beneficial to us and our unitholders. We also seek to encourage a high level of performance from our named executive officers by providing for discretionary awards under our short-term incentive plan for individual performance.

The short-term incentive plan is administered by the Compensation Committee. The Compensation Committee approves the employees who will be participants for each plan year, determines the terms and conditions of awards for such participants, including any goals, determines whether goals are achieved, and whether any awards are paid. The Compensation Committee determines each named executive officer’s short-term incentive target and whether each named executive officer receives any discretionary award. Determinations regarding who will be participants, the terms and conditions of awards, and each named executive officer’s short-term incentive target are made using market data from the Compensation Committee’s consultant. Payment is made in cash no later than March 15 of the year following the plan year and may be subject to any restrictions the Compensation Committee may determine. If eligible, a participant may defer all or a portion of the payment under the deferred compensation plan.

The Compensation Committee may amend, modify, suspend or terminate the short-term incentive plan for the purpose of meeting or addressing any changes in legal requirements or for any other purpose permitted by law, except that no amendment or alteration that would adversely affect the rights of any participant under any award previously granted to such participant may be made without the consent of such participant.

Long -Term Incentives. We adopted the Enable Midstream Partners, LP Long-Term Incentive Plan for our officers, independent directors and employees. The purpose of awards to our named executive officers under our long-term incentive plan is to compensate the named executive officers based on the performance of our common units and their continued employment during the vesting period in order to align their long-term interests with those of our unitholders. Compensating our named executive officers for the long-term performance of our common units supports our pay for performance philosophy. The long-term incentive plan provides for the following types of awards: restricted units, phantom units, appreciations rights, option rights, cash incentive awards, performance units, distribution equivalent rights, and other awards denominated in, payable in, valued in or otherwise based on or related to common units.

The long-term incentive plan is administered by the Compensation Committee. Generally, the Compensation Committee approves the participants, determines the award types, sets the terms and conditions for awards, including performance goals, and determines whether awards are paid, including determining whether performance goals have been met. With respect to any grant of equity as long- term incentive awards to our independent directors and our executive officers subject to reporting under Section 16 of the Exchange Act, the Compensation Committee makes recommendations to the Board of Directors and any such awards will only be effective upon the approval of the Board of Directors. The compensation consultant provides market data to assist the Compensation Committee in making decisions related to the administration of the long-term incentive plan, including determinations regarding the award types, amounts, terms and conditions and goals for our named executive officers. The long-term incentive plan limits the number of units that may be delivered pursuant to vested awards to 13,100,000 common units, subject to proportionate adjustment in the event of unit splits and similar events. Common units cancelled, forfeited, expired or cash settled are available for delivery pursuant to other awards.

The Board of Directors may terminate or amend the long-term incentive plan at any time with respect to any units for which a grant has not yet been made, including amending the long-term incentive plan to increase the number of units that may be granted subject to the requirements of the exchange upon which the common units are listed at that time. However, no change in any outstanding grant may be made that would be adverse to the participant without the consent of the participant.

Upon completion of the IPO, Mr. Sailor received an award of 25,000 restricted units, which will vest on April 16, 2018. The vesting of these awards is contingent upon the executive's employment with us on the vesting date. Notwithstanding the foregoing: (i) in the event we terminate the executive's employment, other than for cause, after the first anniversary of his employment date, a portion of this award will vest upon his termination date based upon the number of days during the four-year vesting period that he is employed by us, but in no event less than 50% of the award amount; (ii) in the event the executive's employment is terminated due to death or disability, by the Partnership within 2 years following a change in control for any reason other than cause, or by the executive for good reason, the award will vest; and (iii) in the event the executive's employment is terminated to due to retirement, a portion of this award will vest upon his retirement based on the number of days during the four-year vesting period that he is employed by us.

In order to compensate them for forfeiting compensation from their previous employers, Mr. Sailor received an award of 137,500 restricted units upon completion of the IPO, Ms. Farmer received an award of 24,000 restricted units upon her employment with us, and Mr. Harris received an award of 19,276 phantom units and 26,986 performance units upon his employment with us. 62,508 units of Mr. Sailor's award vested on March 1, 2015 and 74,992 units vested on March 1, 2016. 12,000 of Ms. Farmer's units vested on September 1, 2015 and and 12,000 units vested on September 1, 2016. 9,638 of Mr. Harris' phantom units will vest on each of September 6, 2017 and September 6, 2018, respectively, and Mr. Harris' performance units award will vest on September 6, 2019. Mr. Harris' performance unit award is subject to the same terms and conditions, described below, as the performance unit awards made to our other named executive officers in 2016. The vesting of each award is contingent upon the executive's employment with us on the vesting date. Notwithstanding the foregoing, each award will vest in the event: (i) we terminate the executive's employment other than for cause within two years following a change in control; (ii) the executive's employment is terminated due to death or disability; or (iii) the executive terminates his employment for good reason within two years following a change in control.

For the restricted unit awards to Mr. Sailor upon the completion of the IPO: (i) "good reason" means our failure to maintain him in at least the position he occupied upon his employment with our general partner or its successor entity, a significant adverse change in his authorities, powers, functions, responsibilities or duties, our failure to perform our obligations with respect to his compensation arrangement, or the relocation of his principal office by more than 50 miles within two years following a change in control; and (ii) termination "for cause" means gross negligence in the performance of duties, conviction of a felony, or intentional misconduct that results in substantial injury to the Partnership. For the other restricted unit awards to our named executive officers, (i) "good reason" means a material reduction in the executive's authority, duties or responsibilities, a decrease in the executive's base salary by more than 10%, a decrease in the executive's target award opportunities under our short-term incentive plan or long-term incentive plan by more than 10%; or a relocation of his or her primary office by more than 50 miles, and (ii) termination "for cause" means a material act or willful misconduct that is materially detrimental to the Partnership, an act of dishonesty in the performance of duties, habitual unexcused absence(s) from work, willful failure to perform duties in any material respect, gross negligence in the performance of duties resulting in material damage or injury to the Partnership or any affiliate, any felony conviction, or any other conviction involving dishonesty, fraud or breach of trust.

Other Compensation and Benefits. Our named executive officers were also eligible to participate in our employee benefit plans and programs, including a medical benefits plan, a 401(k) plan and a non-qualified deferred compensation plan.

Clawback Policy. In May 2016, our Compensation Committee adopted a Clawback Policy for our executive officers. The policy provides that, in the event of an accounting restatement, the Compensation Committee may, within 12 months after the date the Partnership is required to prepare the restatement, require a current or former executive officer to forfeit or return incentive-based compensation they would not have received based on the restatement if the Compensation Committee determines that the

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restatement was caused, in whole or in part, by a willful act or omission of the current or former executive officer. The policy applies to incentive-based compensation under our short term incentive plan and long term incentive plan, and to any other incentive-based compensation, granted on or after January 1, 2016.

Unit Ownership Guidelines. In August 2015, our Compensation Committee adopted Unit Ownership Guidelines for our independent directors and officers. We believe that our Unit Ownership Guidelines align the interests of our independent directors and named executive officers with the interests of our unitholders. The guidelines provide that our Chief Executive Officer should own common units of the Partnership having a market value of five times base salary, the other named executive officers should own common units of the Partnership having a market value of three times their respective base salaries, and that our independent directors should own common units of the Partnership equal to their respective annual base retainers. Our Compensation Committee reviews common unit ownership annually, based on the officer's current base salary or the independent director's current base retainer, and the average closing price for our common units for the previous calendar year. The guidelines were established with advice from the Compensation Committee's consultant.

In addition to units owned directly, units owned indirectly (such as by a spouse or a trust), restricted units and phantom units granted under our long term incentive plan, and performance units granted under our long term incentive plan (at target) count towards the guidelines. The guidelines provide that our existing independent directors and officers should achieve and maintain the minimum ownership levels no later than five years from the adoption of the guidelines. The guidelines also provide that newly appointed independent directors and newly appointed or promoted officers should achieve and maintain the minimum ownership levels no later than five years from the date of appointment, hire or promotion.

2016 Executive Compensation

In 2016, the base salary, short-term incentive award targets, and long-term incentive award targets for our named executive officers were as follows:

Name	Base Salary	Short-Term Incentive Target		Long-Term Incentive Target	
Deanna J. Farmer	$325,000 (increase of 0.0%)	70	%	125	%
Craig Harris	$325,000 (1)	70	%	125	%
John P. Laws	$315,000 (2)	70	%	175	%
Rodney J. Sailor	$600,000 (increase of 33.3%) (3)	100	%	300	%
Mark C. Schroeder	$325,000 (increase of 0.0%)	70	%	125	%

(1) Mr. Harris was hired as Executive Vice President and Chief Commercial Officer on September 6, 2016.
(2) Mr. Laws became Executive Vice President, Chief Financial Officer and Treasurer on January 14, 2016. Prior to January 14, 2016, Mr. Laws served as Vice President and Treasurer.
(3) Mr. Sailor became President and Chief Executive Officer on January 1, 2016. Prior to January 1, 2016, Mr. Sailor served as Executive Vice President and Chief Financial Officer.

Short-Term Incentives. For 2016, the target amount of the short-term incentive award for each named executive officer was a percentage of actual base salary paid during 2016, with a payout ranging from 0% to 150% of the target based on the level of achievement of performance goals established by the Compensation Committee. The award may be increased or decreased at the discretion of the Compensation Committee based on the performance of the named executive officer, but the award may not exceed 200% of the named executive officer's target.

For the 2016 award, the performance goals were based 80% on financial targets and 20% on safety targets. The financial targets consisted of: (i) 30% on operation and maintenance (O&M) and general and administrative (G&A) expense targets, and (ii) 50% on a distributable cash flow (DCF) target. The safety targets consisted of (i) 10% total recordable incident rate (TRIR) targets, which is derived from the Federal Occupational Safety and Health Act of 1970 standards for recordable injuries and illnesses (excluding hearing shifts and any recordable injury resulting from a non-preventable vehicle incident), and (ii) 10% on preventable vehicle incident rate (PVIR) targets, which is defined as one in which the driver failed to exercise every reasonable precaution to prevent the accident. For each performance goal, the Compensation Committee established a minimum level of performance (at which a 50% payout would be made and below which no payout would be made), a target level of performance (at which a 100% payout would be made), and a maximum level of performance (at or above which a 150% payout would be made). The level of payout may range from 0% to 150%, based on the actual performance achieved.

For the purpose of determining the level of performance achieved, the Compensation Committee reserved the right to adjust DCF for (1) increases or decreases resulting from changes in accounting principles that become effective after December 31,

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2015; (2) any increases or decreases in DCF in excess of $5 million in aggregate attributable to any new federal or state laws or regulations enacted after December 31, 2015; and (3) adjustments to reflect the effect of any acquisitions or divestitures occurring during the 2016 plan year as permitted under the plan. The Committee also reserved the right to adjust O&M and G&A for (1) increases or decreases in O&M and G&A attributable to a change in accounting principles effective after December 31, 2015; (2) any increases or decreases in O&M and G&A in excess of $5 million in aggregate attributable to any new federal or state laws or regulations enacted after December 31, 2015; (3) any increases or decreases in O&M attributable to gains, losses, or impairments; (4) any increase or decrease in O&M and G&A expenses attributable to increased STI expense levels above or below the 50% payout level included in the plan targets; (5) any other significant unplanned increases in O&M and G&A expenses occurring during the 2016 plan year approved by the Committee; and (6) adjustments to reflect the effect of any acquisitions or divestitures occurring during the 2016 plan year as permitted under the plan.

The following table shows the minimum, target, and maximum levels of performance for the performance goals set for 2016, the actual level of performance as calculated pursuant to the terms of the awards, and the percentage payout of the targeted amount based on the actual level of performance and as authorized by the Compensation Committee:

	Minimum	Target	Maximum	Actual Performance	% Payout
DCF	$537 million	$552 million	$567 million	$639 million	150%
O&M and G&A	$480 million	$475 million	$450 million	$447 million	150%
Safety Targets					
TRIR	0.614	0.399	0.307	0.657	—%
PVIR	1.038	0.885	0.519	1.251	—%

The DCF actual performance is the amount reported in our 2016 financial statements, without adjustment. The O&M and G&A actual performance is the amounts of O&M and G&A reported in our 2016 financial statements, as adjusted for: (1) certain increases in O&M attributable to gains, losses, or impairments; (2) an increase in O&M and G&A expenses attributable to increased STI expense levels above the $10.6 million, 50% payout level included in the plan targets.

Long-Term Incentives. For 2016, each named executive officer, other than Mr. Harris, received a long-term incentive award, allocated 80% to performance units and 20% to phantom units, in each case with distribution equivalent rights under the long-term incentive plan that will vest on April 1, 2019, subject to the satisfaction of vesting criteria. Upon his employment with us in 2016, Mr. Harris received a long-term incentive award of 19,276 phantom units and 26,986 performance units, in each case with distribution equivalent rights under the long-term incentive plan. 9,638 of the phantom units will vest on September 6, 2017, 9,638 of the phantom units will vest on September 6, 2018 and any performance units earned will vest on September 6, 2019. Our named executed officers received the following 2016 performance unit and phantom unit awards:

Name	Performance Award	Phantom Award
Deanna J. Farmer	46,830	11,708
Craig Harris	26,986	19,276
John P. Laws	63,544	15,887
Rodney J. Sailor	207,492	51,874
Mark C. Schroeder	46,830	11,708

The performance units awarded in 2016 have a payout ranging from 0% to 200% of the target based on the level of achievement of a performance goal established by the Board of Directors over a performance period of January 1, 2016 through December 31, 2018. Performance units earned will be paid in the Partnership’s common units, and distribution equivalent rights will be paid in cash at vesting.

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For the awards in 2016, the performance goal was based on the relative total unitholder return (TUR) of our common units over the performance period compared to a peer group. The peer group consists of the following companies, which may be adjusted by the Compensation Committee, as necessary, from time to time:

Antero Midstream Partners LP	EQT Midstream Partners LP
Archrock Partners, L.P.	MPLX LP
Boardwalk Pipeline Partners, LP	ONEOK Partners, L.P.
Columbia Pipeline Partners LP	Spectra Energy Partners, LP
Crestwood Midstream Partners LP	Summit Midstream Partners, LP
DCP Midstream Partners, LP	Targa Resources Partners LP
Dominion Midstream Partners LP	TC PipeLines, LP
Energy Transfer Partners, L.P.	Western Gas Partners, LP
EnLink Midstream, LP	Williams Partners, L.P.
Enterprise Products Partners L.P.	

If our TUR ranking among the peer group over the performance period is below the 30^{th} percentile, no performance units will vest. If our TUR ranking is greater than or equal to the 30^{th} percentile but less than the 50^{th} percentile, 50%-100% of the performance units will vest. If our TUR ranking is greater than or equal to the 50^{th} percentile but less than the 75^{th} percentile, 101%-150% of the performance units will vest. If our TUR ranking is greater than or equal to the 75^{th} percentile but less than the 90^{th} percentile, 151%-199% of the performance units will vest. If our TUR ranking is greater than or equal to the 90^{th} percentile, 200% of the performance units will vest. If our ranking falls between these percentages, vesting will be determined by straight-line interpolation.

Phantom units will be paid in the Partnership's common units, and distribution equivalent rights will be paid in cash during the term of the award. The vesting of both the performance unit and phantom unit award are contingent upon the executive's employment with us on the vesting date. Notwithstanding the foregoing: (i) in the event the executive's employment is terminated due to death or disability, we terminate the executive's employment other than for cause within two years following a change in control, or the executive terminates his employment with us for good reason within two years following a change in control, the awards will vest; and (ii) in the event the executive's employment is terminated due to retirement, a portion of the awards will vest upon their retirement based on the number of days during the three-year vesting period that they are employed by us.

For both the performance unit and phantom unit awards to our named executive officers: (i) "good reason" means a material reduction in the executive's authority, duties or responsibilities, a decrease in the executive's base salary by more than 10%, a decrease in the executive's target award opportunities under our short-term incentive plan or long-term incentive plan by more than 10%; or a relocation of the executive's primary office by more than 50 miles, and (ii) termination "for cause" means a material act or willful misconduct that is materially detrimental to the Partnership, an act of dishonesty in the performance of duties, habitual unexcused absence(s) from work, willful failure to perform duties in any material respect, gross negligence in the performance of duties resulting in material damage or injury to the Partnership or any affiliate, any felony conviction, or any other conviction involving dishonesty, fraud or breach of trust.

2017 Executive Compensation

In February 2017, the Compensation Committee reviewed the base salaries and long-term incentive award targets for our named executive officers, and the Board of Directors reviewed the long-term incentive targets for our named executive officers, in each case in comparison to market data provided by the Compensation Committee's consultant. For 2017, the base salaries and long-term incentive targets for the following executive officers are:

Name	Base Salary	Long-Term Incentive Target
Deanna J. Farmer	$339,625 (increase of 4.50%)	135 %
Craig Harris	$325,000 (increase of 0.0%)	135 %
John P. Laws	$362,250 (increase of 15.00%)	185 %
Rodney J. Sailor	$650,000 (increase of 8.33%)	300 %
Mark C. Schroeder	$338,813 (increase of 4.25%)	135 %

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Short-Term Incentives. The Compensation Committee has not yet determined the 2017 short-term incentive performance goals and targets for our named executive officers.

Long-Term Incentives. For 2017, our named executive officers' long-term incentive awards will be allocated 65% to performance units and 35% to phantom units. The 2017 performance unit awards will be consistent with 2016, including having distribution equivalent rights and being based on total unitholder return over a three-year performance cycle. For 2017, total unitholder return will be based on the relative performance of our common units compared to the following peer group, which may be adjusted by the Compensation Committee, as necessary, from time to time:

Antero Midstream Partners LP	EQT Midstream Partners, LP
Boardwalk Pipeline Partners, LP	MPLX LP
Crestwood Midstream Partners LP	ONEOK Partners, L.P.
Cheniere Energy Partners, L.P.	Rice Midstream Partners LP
DCP Midstream, LP	Spectra Energy Partners, LP
Energy Transfer Partners, L.P.	TC PipeLines, LP
EnLink Midstream, LP	Western Gas Partners, LP
Enterprise Products Partners L.P.	Williams Partners L.P.

The phantom unit awards will have distribution equivalent rights paid during the term of the award and will vest three years from the date of grant. The vesting of both phantom unit and performance unit awards will be contingent upon the executive's employment with us on the vesting date. Notwithstanding the foregoing: (i) in the event the executive's employment is terminated due to death or disability, we terminate the executive's employment other than for cause within two years following a change in control, or the executive terminates his employment with us for good reason within two years following a change in control, the award will vest; and (ii) in the event the executive's employment is terminated due to retirement, a portion of this award will vest upon his or her retirement based on the number of days during the three-year vesting period that he or she is employed by us. "Good reason" and "for cause" have will have the same meanings for phantom unit awards as they do for performance unit awards.

For both performance unit awards and phantom unit awards, the Board determined that the date of grant will be March 1, 2017. Provided that they are employed by us on the date of grant, our named executive officers will receive the following 2017 performance unit and phantom unit awards:

Name	Performance Awards	Phantom Awards
Deanna J. Farmer	18,116	9,756
Craig Harris	17,336	9,336
John P. Laws	26,481	14,259
Rodney J. Sailor	77,052	41,490
Mark C. Schroeder	18,074	9,732

Executive Compensation Tables

The following table summarizes the compensation for our named executive officers for the years ended December 31, 2016, 2015 and 2014. For all our named executive officers, the table includes all compensation awarded by or paid by us during the years ended December 31, 2016, 2015 and 2014. For Mr. Schroeder, the table also includes all compensation expenses reimbursed to CenterPoint Energy from his secondment to us on March 1, 2014 through December 31, 2014.

We are not providing, and the table does not include, compensation for Mr. Schroeder prior to his secondment to us on March 1, 2014. From our formation on May 1, 2013 through February 28, 2014, Mr. Schroeder provided services to us pursuant to a services agreement with CenterPoint Energy. Amounts allocated to us for services provided to us by Mr. Schroeder during this period were based on an allocation of overhead and other costs of the services provided. On March 1, 2014, Mr. Schroeder was seconded to us under our transitional seconding agreement with CenterPoint Energy.

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Summary Compensation Table for 2016

Name and Principal Position	Year	Salary ($)	Bonus ($)	Stock Awards ($)(1)	Option Awards ($)	Non-Equity Incentive Plan Compensation ($)(2)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($)(3)	All Other Compensation ($)(4)	Total ($)
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
Deanna J. Farmer Executive Vice	2016	325,000	—	583,038	—	273,000	—	72,964	1,254,002
President and Chief Administrative Officer	2015	311,846	—	398,575	—	117,054	—	67,511	894,986
	2014	81,173 [5]	182,000 [9]	591,600 [11]	—	—	—	15,787	870,560
Craig Harris Executive Vice President and Chief Commercial Officer	2016	92,500 [6]	—	1,041,432 [12]	—	77,700	—	28,655	1,240,287
John P. Laws Executive Vice President, Chief Financial Officer, and Treasurer	2016	309,877	—	791,130	—	260,297	—	63,588	1,424,892
Rodney J. Sailor	2016	594,808	—	2,583,284	—	713,769	—	171,997	4,063,858
President and Chief Executive Officer	2015	436,154	—	882,970	—	278,720		192,111	1,789,955
	2014	339,231 [7]	125,000 [10]	4,710,503 [13]	—	379,600	—	115,196	5,669,530
Mark C. Schroeder Executive Vice	2016	325,000	—	583,038	—	273,000	—	63,103	1,244,141
President and General Counsel	2015	307,115	—	398,575	—	115,278	—	57,695	878,663
	2014	250,001 [8]	—	461,810	—	155,000	30,908	50,854	948,573

(1) Amounts in this column reflect the aggregate grant date fair value amount of the Partnership equity based unit awards granted to each named executive officer. The grant date fair value amount of performance unit awards is computed in accordance with FASB ASC Topic 718 based on the probable achievement level of the underlying performance conditions as of the grant date. Please refer to the Grants of Plan-Based Awards table for 2016 and the accompanying footnotes. Assuming achievement of the performance goals at the maximum level, the grant date fair value of the performance units granted in 2016 and included in this column would be $975,938 for Ms. Farmer, $1,498,802 for Mr. Harris, $1,324,256 for Mr. Laws, $4,324,134 for Mr. Sailor and $975,938 for Mr. Schroeder. Assuming achievement of the performance goals at the maximum level, the grant date fair value of the performance units granted in 2015 and included in this column would be $797,150 for Ms. Farmer, $1,765,939 for Mr. Sailor and $797,150 for Mr. Schroeder. Assuming achievement of the performance goals at the maximum level, the grant date fair value of the performance units granted in 2014 and included in this column would be $2,076,006 for Mr. Sailor and $692,019 for Mr. Schroeder. The grant date fair value amount of phantom unit awards and restricted unit awards are computed in accordance with FASB ASC Topic 718. See Note 17 to the financial statements for a discussion of the valuation assumptions used for these awards.

(2) Amounts in this column reflect amounts earned under the Partnership's Short-Term Incentive Plan.

(3) Amounts in this column reflect the actuarial increase in the present value of Mr. Schroeder's benefits under CenterPoint Energy's qualified defined benefit pension plans as reported to us by CenterPoint Energy, which CenterPoint Energy has represented to us was reported in the Notes to CenterPoint Energy's Consolidated Financial Statements for the year ended December 31, 2014 that was included in CenterPoint Energy's 10-K for the year ended December 31, 2014. Under the terms of the Master Formation Agreement, the Partnership has no current or future liability for any accumulated pension obligations under CenterPoint Energy's qualified defined benefit pension plans. During 2014, the Partnership reimbursed CenterPoint Energy for the aggregate period costs recognized by CenterPoint Energy in accordance with FASB ASC Topic 718 attributable to participants seconded to us by CenterPoint Energy. Such period costs were not allocated to individual participants.

(4) The following table sets forth the elements of All Other Compensation for 2016, 2015 and 2014.

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Name (14)		401(k) Plan Matching Contributions ($)	Non-Qualified Matching Contributions ($)	Distribution Equivalent Rights ($)	Supplemental Life Insurance ($)	Long Term Disability ($)	Other ($)(15)	Total ($)
Deanna J. Farmer	2016	29,150	19,476	22,617	953	768	—	72,964
	2015	29,150	10,653	26,310	630	768	—	67,511
	2014	8,527	—	7,260	—	—	—	15,787
Craig Harris	2016	4,625	3,500	6,130	223	177	14,000	28,655
John P. Laws	2016	29,150	12,040	20,164	420	768	1,046	63,588
Rodney J. Sailor	2016	29,150	66,938	73,335	1,806	768	—	171,997
	2015	29,150	60,583	99,804	1,806	768	—	192,111
	2014	26,000	—	89,196	—	—	—	115,196
Mark C. Schroeder	2016	29,150	19,281	11,169	2,735	768	—	63,103
	2015	29,150	21,683	4,288	1,806	768	—	57,695
	2014	13,000	9,731	22,642	107	759	4,615	50,854

(5) Represents salary from hire date on September 29, 2014 to December 31, 2014.

(6) Represents salary from hire date on September 6, 2016 to December 31, 2016.

(7) Represents salary from hire date on April 1, 2014 to December 31, 2014.

(8) Represents salary during secondment to the Partnership from March 1, 2014 to December 31, 2014.

(9) Amount represents a $132,000 signing bonus upon employment with the Partnership and a $50,000 discretionary bonus. Although Ms. Farmer was not eligible to receive an award for 2014 under the Partnership's Short-Term Incentive Plan, the Compensation Committee elected to pay Ms. Farmer a discretionary bonus of $50,000 that was calculated in accordance with the methodology used for 2014 awards to named executive officers under the Short-Term Incentive Plan.

(10) Amount represents a signing bonus upon employment with the Partnership.

(11) Amounts include an award of 24,000 restricted units Ms. Farmer received upon employment with the Partnership, of which 12,000 units vested on September 1, 2015 (3,913 of these units were withheld for taxes) and 12,000 units vested on September 1, 2016 (3,882 of these units were withheld for taxes). Awards granted to Ms. Farmer in 2014 were calculated based on the closing price of the Partnership's common units, as reported on the NYSE on the grant date.

(12) Amounts include an award of 19,276 phantom units Mr. Harris received upon employment with the Partnership, of which 9,638 units will vest on September 6, 2017 and 9,638 units will vest on September 6, 2018. Awards granted to Mr. Harris in 2016 were calculated based on the closing price of the Partnership's common units, as reported on the NYSE on the grant date.

(13) Amounts include an award of 25,000 restricted units Mr. Sailor received upon completion of the IPO which will vest on April 16, 2018; 137,500 restricted units Mr. Sailor received upon completion of the IPO, of which 62,508 units vested on March 1, 2015 (21,801 of these units were withheld for taxes) and 74,992 units vested on March 1, 2016 (24,207 of these units were withheld for taxes). Awards granted to Mr. Sailor in 2014 were calculated based on the closing price of the Partnership's common units, as reported on the NYSE on the grant date.

(14) Other than Mr Harris, none of our named executive officers received perquisites valued in excess of $10,000 in 2016.

(15) Amounts include $14,000 of travel allowance for Mr. Harris, $1,046 of tax gross up for Mr. Laws and $4,615 of vacation payout for Mr. Schroeder.

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Grants of Plan-Based Awards Table for 2016

The following Grants of Plan-Based Awards Table summarizes the grants of plan-based awards made to named executive officers during 2016.

Name	Grant Date	Board Approval Date	Estimated Future Payouts Under Non-Equity Incentive Plan Awards (1)			Estimated Future Payouts Under Equity Incentive Plan Awards (2)			All Other Stock Awards: Number of Shares of Stock or Units (#) (3)	Grant Date Fair Value of Stock Awards ($)(4)
			Threshold ($)	Target ($)	Maximum ($)	Threshold (#)	Target (#)	Maximum (#)		
(a)	(b)		(c)	(d)	(e)	(f)	(g)	(h)	(i)	(l)
Deanna J. Farmer	03/30/2016	03/30/2016	113,750	227,500	455,000	—	—	—	—	—
	04/01/2016	02/16/2016	—	—	—	23,415	46,830	93,660	—	487,969
	04/01/2016	02/16/2016	—	—	—	—	—	—	11,708	95,069
Craig Harris	09/06/2016(5)	08/22/2016	32,375	64,750	129,500	13,493	26,986	53,972	—	749,401
	09/06/2016(5)	08/22/2016	—	—	—	—	—	—	19,276	292,031
John P. Laws	03/30/2016	03/30/2016	108,457	216,914	433,828	—	—	—	—	—
	04/01/2016	02/16/2016	—	—	—	31,772	63,544	127,088	—	662,128
	04/01/2016	02/16/2016	—	—	—	—	—	—	15,887	129,002
Rodney J. Sailor	03/30/2016	03/30/2016	297,404	594,808	1,189,616	—	—	—	—	—
	04/01/2016	02/16/2016	—	—	—	103,746	207,492	414,984	—	2,162,067
	04/01/2016	02/16/2016	—	—	—	—	—	—	51,874	421,217
Mark C. Schroeder	03/30/2016	03/30/2016	113,750	227,500	455,000	—	—	—	—	—
	04/01/2016	02/16/2016	—	—	—	23,415	46,830	93,660	—	487,969
	04/01/2016	02/16/2016	—	—	—	—	—	—	11,708	95,069

(1) Amounts in columns (c), (d) and (e) of the Grants of Plan-Based Awards Table for 2016 above represent the threshold, target and maximum amounts that would be payable to named executive officers pursuant to the 2016 annual incentive awards made under the Enable Midstream Partners, LP Short-Term Incentive Plan. The short-term incentive plan was designed with a funding trigger that requires threshold performance for the plan to payout. If threshold performance is not met, no payments will be made. For each performance measure, established thresholds were set (at which 50% payout would be made), a target level of performance (at which a 100% payout would be made) and a maximum level of performance (at or above which a 150% payout would be made) based on eligible earnings. The award may be increased or decreased at the Compensation Committee’s discretion based on the performance of the named executive officer, but the award may not exceed 200% of the named executive officer’s target. As discussed in the Compensation Discussion and Analysis above, the amount that each executive

officer will receive is dependent upon Partnership performance against a distributable cash flow target (50%), operations & maintenance and general & administrative expense (30%) and an aggregate safety target (20%).

(2) Amounts in columns (f), (g) and (h) above represent awards of performance units under Enable Midstream Partners, LP Long-Term Incentive Plan. All payouts of such performance units will be made in units and any accumulated distribution equivalent rights will be paid in cash. Due to their variable nature, accumulated distribution equivalent rights are not disclosed in the table above. The conditions of the 2016 award entitle the named executive officer to receive from 0% to 200% of the performance units granted depending upon the Partnership's total unitholder return over a three-year period (defined as unit price increase (decrease) since December 31, 2015 plus distributions paid, divided by unit price at December 31, 2015) measured against the total unitholder return for such period of our performance peer group consisting of 19 companies. At the end of the three-year period (i.e., December 31, 2018), the terms of these performance units provide for payout of 100% of the performance units initially granted if the Partnership's total unitholder return is at the 50th percentile of the peer group, with higher payouts for performance above the 50th percentile up to 200% of the performance units granted if total unitholder return is at or above the 90th percentile of the peer group. The terms of these performance units provide for payouts of less than 100% of the performance units granted if the Partnership's total unitholder return is below the 50th percentile of the peer group, with no payout for performance below the 30th percentile.

(3) Amounts in column (i) above represent the number of phantom unit awards granted to each of our named executive officers under the Enable Midstream Partners, LP Long-Term Incentive Plan.

(4) Amounts reflect the grant date fair value based on a probable value of these awards or target value, of 100% payout. See Note 17 to the financial statements for further information.

(5) These awards were received upon Mr. Harris's employment with the Partnership, which was effective on September 6, 2016.

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Outstanding Equity Awards at 2016 Fiscal Year-End Table

Name	Unit Awards				
	Number of Units That Have Not Vested (#)	Market Value of Units That Have Not Vested ($)	Equity Incentive Plan Awards: Number of Unearned Units or Other Rights That Have Not Vested (#)		Equity Incentive Plan Awards: Market Value of Unearned Units or Other Rights That Have Not Vested ($)
(a)	(g)	(h)	(i)		(j)
Deanna J. Farmer	11,708 (1)	184,167	23,415	(5)	368,318
	—	—	12,013	(6)	188,964
Craig Harris	19,276 (2)	303,211	13,493	(7)	212,245
John P. Laws	15,887 (1)	249,903	31,772	(5)	499,774
	3,937 (3)	61,929	3,207	(6)	50,446
	—	—	5,395	(8)	84,863
Rodney J. Sailor	51,874 (1)	815,978	103,746	(5)	1,631,925
	25,000 (4)	393,250	26,612	(6)	418,607
	—	—	40,706	(8)	640,305
Mark C. Schroeder	11,708 (1)	184,167	23,415	(5)	368,318
	—	—	12,013	(6)	188,964
	—	—	13,569	(8)	213,440

(1) This amount represents a time-based phantom unit award under the Enable Midstream Partners long-term incentive plan scheduled to vest on April 1, 2019. Values were calculated based on a $15.73 closing price of the Partnership's common units, as reported on the NYSE at December 31, 2016.

(2) This amount represents two time-based phantom unit awards under the Enable Midstream Partners long-term incentive plan, of which 9,638 will vest on September 6, 2017 and 9,638 will vest on September 6, 2018. Values were calculated based on a $15.73 closing price of the Partnership's common units, as reported on the NYSE at December 31, 2016.

(3) This amount represents two restricted unit awards under the Enable Midstream Partners long-term incentive plan, of which 1,799 will vest on June 2, 2017 and 2,138 will vest on June 1, 2018. Values were calculated based on a $15.73 closing price of the Partnership's common units, as reported on the NYSE at December 31, 2016.

(4) This amount represents a restricted unit award under the Enable Midstream Partners long-term incentive plan which will vest on April 16, 2018. Values were calculated based on a $15.73 closing price of the Partnership's common units, as reported on the NYSE at December 31, 2016.

(5) This amount represents a performance unit award under the Enable Midstream Partners long-term incentive plan. The performance cycle began on January 1, 2016 and ends December 31, 2018. The number of units listed reflects the number of units paid at threshold performance. The value of the awards were calculated based on threshold payout of 50% and a $15.73 closing price of the Partnership's common units, as reported on the NYSE on December 31, 2016. This award will vest on April 1, 2019.

(6)

This amount represents a performance unit award under the Enable Midstream Partners long-term incentive plan. The performance cycle began on January 1, 2015 and ends December 31, 2017. The number of units listed reflects the number of units paid at threshold performance. The value of the awards were calculated based on threshold payout of 50% and a $15.73 closing price of the Partnership’s common units, as reported on the NYSE on December 31, 2016. This award will vest on June 1, 2018.

(7) This amount represents a performance unit award under the Enable Midstream Partners long-term incentive plan granted on September 6, 2016. The performance cycle began on January 1, 2016 and ends December 31, 2018. The number of units listed reflects the number of units paid at threshold performance. The value of the awards were calculated based on threshold payout of 50% and a $15.73 closing price of the Partnership's common units, as reported on the NYSE on December 31, 2016. This award will vest on September 6, 2019.

(8) This amount represents a performance unit award under the Enable Midstream Partners long-term incentive plan. The performance cycle began on April 11, 2014 and ends December 31, 2016. The number of units listed reflects the number of units paid at target performance. The value of the awards were calculated based on target payout of 100% and a $15.73 closing price of the Partnership’s common units, as reported on the NYSE on December 31, 2016. These awards will vest on June 1, 2017.

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2016 Option Exercises and Stock Vested Table

	Stock Awards	
Name	Number of Shares Acquired on Vesting (#)	Value Realized on Vesting ($) (5)
(a)	(d)	(e)
Deanna J. Farmer	12,000 (1)	170,880
Craig Harris	—	—
John P. Laws	—	—
Rodney J. Sailor	74,992 (2)	461,951
Mark C. Schroeder	3,525 (3)	65,318
	2,000 (4)	36,880

(1) This amount reflects the distribution of 12,000 restricted units granted on September 29, 2014. The units vested on September 1, 2016 and the award was paid out in units of the Partnership.

(2) This amount reflects the distribution of 74,992 restricted units granted on April 16, 2014. The units vested on March 1, 2016 and the award was paid out in units of the Partnership.

(3) Reflects the value of the payout of CenterPoint Energy performance units granted in January 2013 for performance period ending December 31, 2015. Performance was based on 50% total shareholder return and 50% earnings per share, the combined achievement, as certified by CenterPoint Energy's Board, resulting in a payout of 3,525 shares of CenterPoint Energy's common stock, the cost of which was reimbursed by the Partnership.

(4) Reflects the value of the payout of CenterPoint Energy stock award granted in February 2013. The vesting of the stock award was subject to the participant's continued employment and the ability of CenterPoint Energy to declare a dividend of at least $2.49 per share over the three year period ending December 31, 2015. Awards were paid out in shares of CenterPoint Energy's common stock, the cost of which was reimbursed by the Partnership.

(5) For each named executive officer, excluding Mr. Schroeder, the value of the awards were calculated based on the closing price of the Partnership's common units, as reported on the NYSE on the date of vesting. For Mr. Schroeder, the value of the awards were calculated based on the closing price of CenterPoint Energy's common stock, as reported on the NYSE on the date of vesting.

2016 Nonqualified Deferred Compensation

Name	Executive Contributions in Last FY ($)	Registrant Contributions in Last FY ($)(1)	Aggregate Earnings in Last FY ($)(2)	Aggregate Withdrawals/Distributions ($)	Aggregate Balance at Last FYE ($)(1)
(a)	(b)	(c)	(d)	(e)	(f)
Deanna J. Farmer	—	15,466	1,271	—	22,547
Craig Harris	3,500	3,500	76	—	7,076
John P. Laws					