UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

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

For the fiscal year ended December 31, 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 number: 000-50067

ENLINK MIDSTREAM PARTNERS, LP

(Exact name of registrant as specified in its charter)

Delaware (State of organization)	**16-1616605** (I.R.S. Employer Identification No.)
2501 CEDAR SPRINGS **DALLAS, TEXAS** (Address of principal executive offices)	**75201** (Zip Code)

(Registrant's telephone number, including area code)
(214) 953-9500

SECURITIES REGISTERED PURSUANT TO SECTION 12(b) OF THE ACT:

Title of Each Class	Name of Exchange on which Registered
Common Units Representing Limited Partnership Interests	The New York Stock Exchange

SECURITIES REGISTERED PURSUANT TO SECTION 12(g) OF THE ACT: **None.**

Indicate by check mark if registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☒ No ☐

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§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 Securities Exchange Act. (Check one):

Large accelerated filer ☒	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 Act). Yes ☐ No ☒

The aggregate market value of the common units representing limited partner interests held by non-affiliates of the registrant was approximately $2.5 billion on June 30, 2016, based on $16.63 per unit, the closing price of the common units as reported on The New York Stock Exchange on such date.

At February 8, 2017, there were 342,882,825 common units outstanding.

DOCUMENTS INCORPORATED BY REFERENCE:

None.

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ENLINK MIDSTREAM PARTNERS, LP

PART I

Item 1. Business

General

EnLink Midstream Partners, LP is a publicly traded Delaware limited partnership formed in 2002. Our common units are traded on the New York Stock Exchange ("NYSE") under the symbol "ENLK." Our business activities are conducted through our subsidiary, EnLink Midstream Operating, LP, a Delaware limited partnership (the "Operating Partnership"), and the subsidiaries of the Operating Partnership. Our executive offices are located at 2501 Cedar Springs Rd., Dallas, Texas 75201, and our telephone number is (214) 953-9500. Our Internet address is www.enlink.com. We post the following filings in the "Investors" section of our website as soon as reasonably practicable after they are electronically filed with or furnished to the Securities and Exchange Commission: our annual reports on Form 10-K; our quarterly reports on Form 10-Q; our current reports on Form 8-K; and any amendments to those reports or statements filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended. All such filings on our website are available free of charge. 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 EnLink Midstream Partners, LP itself or EnLink Midstream Partners, LP together with its consolidated subsidiaries, including the Operating Partnership.

EnLink Midstream GP, LLC, a Delaware limited liability company, is our general partner. Our general partner manages our operations and activities. Our general partner is an indirect, wholly-owned subsidiary of EnLink Midstream, LLC ("ENLC" or "EnLink Midstream"). ENLC's units are traded on the NYSE under the symbol "ENLC." ENLC's manager is an indirect, wholly-owned subsidiary of Devon Energy Corporation ("Devon").

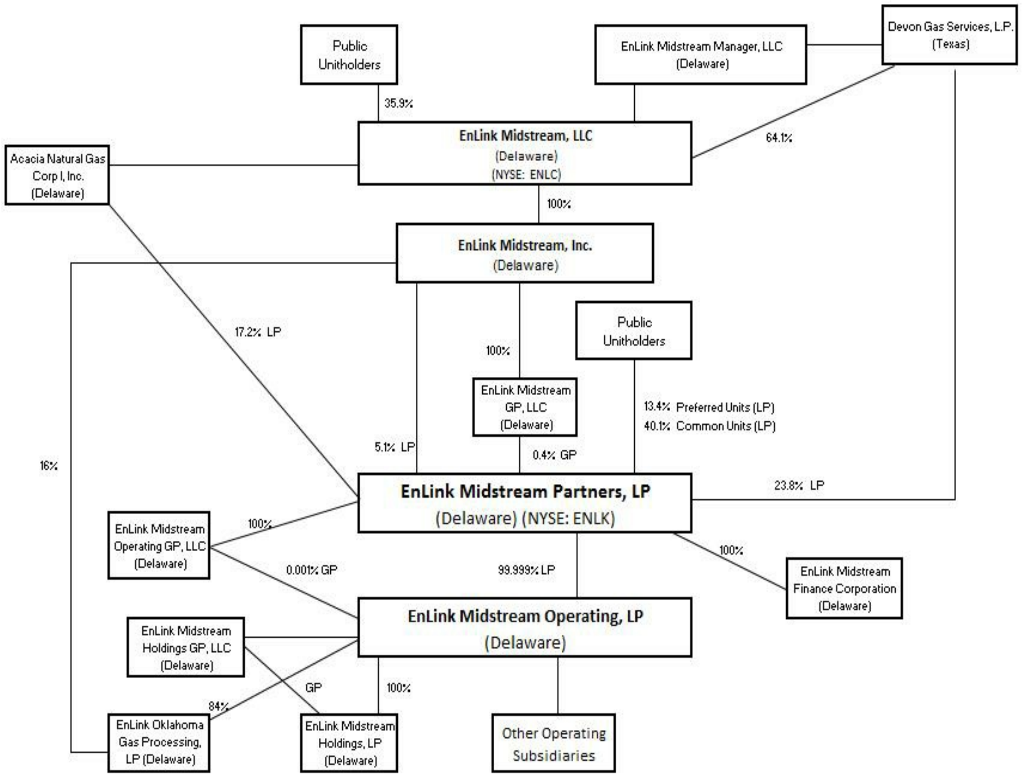
Effective as of March 7, 2014, the Operating Partnership acquired (the "Acquisition") 50% of the outstanding equity interests in EnLink Midstream Holdings, LP ("Midstream Holdings") and all of the outstanding equity interests in EnLink Midstream Holdings GP, LLC, the general partner of Midstream Holdings, in exchange for the issuance by us of 120,542,441 units representing a new class of limited partnership interests in our partnership. At the same time, EnLink Midstream, Inc. ("EMI"), the entity that directly owns our general partner, became a wholly-owned subsidiary of ENLC (together with the Acquisition, the "Business Combination"). At the conclusion of the Business Combination, another wholly-owned subsidiary of ENLC, Acacia Natural Gas Corp. I, Inc. ("Acacia"), owned the remaining 50% of the outstanding equity interests in Midstream Holdings. On February 17, 2015, Acacia contributed a 25% interest in Midstream Holdings (the "February 2015 Transferred Interests") to us in exchange for 31.6 million units in our partnership (the "February 2015 EMH Drop Down"). On May 27, 2015, we acquired the remaining 25% limited partner interest in Midstream Holdings (the "May 2015 Transferred Interests" and, together with the February 2015 Transferred Interests, the "2015 Transferred Interests") from Acacia in a drop-down transaction in exchange for 36.6 million units in our partnership (the "May 2015 EMH Drop Down" and, together with the February 2015 EMH Drop Down, the "EMH Drop Downs"). After giving effect to the EMH Drop Downs, we own 100% of Midstream Holdings.

Midstream Holdings was formerly a wholly-owned subsidiary of Devon, and it gathers, processes and transports natural gas, primarily for Devon. Midstream Holdings also fractionates natural gas liquids ("NGLs") into component NGL products. Under the acquisition method of accounting, Midstream Holdings is considered the historical predecessor of our business because Devon obtained control of us through its control of ENLC and through the indirect acquisition of our general partner.

On January 7, 2016, EnLink Oklahoma Gas Processing, LP ("EnLink Oklahoma T.O."), an indirect subsidiary of our partnership, completed its acquisition of 100% of the issued and outstanding membership interests of TOMPC LLC and TOM-STACK, LLC. EnLink Oklahoma T.O. is sometimes used herein to refer to EnLink Oklahoma Gas Processing, LP itself or EnLink Oklahoma Gas Processing, LP, together with its consolidated subsidiaries. As of February 12, 2016, (a) the Operating Partnership, owns an 84% limited partnership interest in EnLink Oklahoma T.O.; (b) EMI owns a 16% limited partnership interest in EnLink Oklahoma T.O. and (c) EnLink Energy GP, LLC, the general partner of EnLink Oklahoma T.O. and an indirect subsidiary of our partnership, owns the non-economic general partnership interest.

On August 1, 2016, we formed a joint venture (the "Delaware Basin JV") with an affiliate of NGP Natural Resources XI, L.P. ("NGP") to operate and expand our natural gas, NGLs and crude oil midstream assets in the liquids-rich Delaware Basin. The Delaware Basin JV is owned 50.1% by us and 49.9% by NGP. Since we control the Delaware Basin JV, we reflect our ownership in the Delaware Basin JV on a consolidated basis, and NGP's ownership is reflected as a non-controlling interest in the respective consolidated financial statements and related disclosures.

The following diagram depicts our organization and ownership as of December 31, 2016:



Definitions

The following terms as defined generally are used in the energy industry and in this document:

/d = per day
Bbls = barrels
Bcf = billion cubic feet
Boe = six Mcf of gas per Bbl of oil
Btu = British thermal units
CO_2= Carbon dioxide
CPI= Consumer Price Index
Gal = gallon
HP = horsepower
Mcf = thousand cubic feet
MMBtu = million British thermal units
MMcf = million cubic feet
NGL = natural gas liquid and natural gas liquids

Capacity volumes for our facilities are measured based on physical volume and stated in cubic feet ("Bcf", "Mcf" or "MMcf"). Throughput volumes are measured based on energy content and stated in British thermal units ("Btu" or "MMBtu"). A volume capacity of 100 MMcf generally correlates to volume capacity of 100,000 MMBtu. Fractionated volumes are measured based on physical volumes and stated in gallons. Crude oil, condensate and brine services volumes are measured based on physical volume and stated in barrels ("Bbls").

We define "gross operating margin," a non-GAAP financial measure, as revenues less cost of sales. We disclose gross operating margin in addition to total revenue because it is the primary performance measure used by our management. We believe gross operating margin is an important measure because, in general, our business is to purchase and resell natural gas, NGLs, condensate and crude oil for a margin or to gather, process, transport or market natural gas, NGLs, condensate and crude oil for a fee. The GAAP measure most directly comparable to gross operating margin is operating income (loss). For more information on gross operating margin, including its limitations as a financial measure, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Non-GAAP Financial Measures."

Our Operations

We are a Delaware limited partnership formed on July 12, 2002. We primarily focus on providing midstream energy services, including gathering, transmission, processing, fractionation, storage, condensate stabilization, brine services and marketing, to producers of natural gas, NGLs, crude oil and condensate. Our midstream energy asset network includes approximately 11,000 miles of pipelines, 20 natural gas processing plants, 7 fractionators, barge and rail terminals, product storage facilities, purchasing and marketing capabilities, brine disposal wells, a crude oil trucking fleet, and equity investments in certain private midstream companies. Our operations are based in the United States and our sales are derived primarily from external domestic customers.

We connect the wells of natural gas producers in our market areas to our gathering systems, process natural gas for the removal of NGLs, fractionate NGLs into purity products and market those products for a fee, transport natural gas and ultimately provide natural gas to a variety of markets. We purchase natural gas from natural gas producers and other supply sources and sell that natural gas to utilities, industrial consumers, other marketers and pipelines. We operate processing plants that process gas transported to the plants by major interstate pipelines or from our own gathering systems under a variety of fee-based arrangements. We provide a variety of crude oil and condensate services, which include crude oil and condensate gathering via pipelines, barges, rail and trucks, condensate stabilization and brine disposal. Our gas gathering systems consist of networks of pipelines that collect natural gas from points near producing wells and transport it to larger pipelines for further transmission. Our transmission pipelines primarily receive natural gas from our gathering systems and from third party gathering and transmission systems and deliver natural gas to industrial end-users, utilities and other pipelines. We also have transmission lines that transport NGLs from east Texas and from our south Louisiana processing plants to our fractionators in south Louisiana. Additionally, we own an economic interest in an NGL fractionator located at Mont Belvieu, Texas that receives raw mix NGLs from customers, fractionates such raw mix and redelivers the finished products to the customers for a fee. Devon is one of the largest customers of this fractionator. Our crude oil and condensate gathering and transmission systems consist of trucking facilities, pipelines, rail and barge facilities that, in exchange for a fee, transport oil from a producer site to end users or other pipelines. Our processing plants remove NGLs and CO_2 from a natural gas stream and our fractionators separate the NGLs into separate NGL products, including ethane, propane, iso-butane, normal butane and natural gasoline.

Our assets are included in five primary segments:

- *Texas*. Our Texas assets consist of transmission pipelines with a capacity of approximately 920 MMcf/d, processing facilities with a total processing capacity of approximately 1.6 Bcf/d and gathering systems with total capacity of approximately 2.3 Bcf/d.

- *Oklahoma.* Our Oklahoma assets consist of processing facilities with a total processing capacity of approximately 795 MMcf/d and gathering systems with total capacity of approximately 810 MMcf/d.

- *Louisiana.* Our Louisiana Gas and Processing assets include transmission pipelines with a capacity of approximately 3.5 Bcf/d, processing facilities with a total processing capacity of approximately 1.9 Bcf/d and gathering systems with total capacity of approximately 510 MMcf/d. Our Louisiana Liquids assets consist of

720 miles of liquids transport lines and four fractionation assets with total fractionation capacity of 175 MBbls/d.

- *Crude and Condensate.* Our Crude and Condensate assets consist of approximately 540 miles of crude oil and condensate pipelines. The assets also include 900,000 barrels of above ground storage and a trucking fleet of approximately 150 vehicles comprised of both semi and straight trucks with a current capacity of 85,350 Bbls/d. The current pipeline capacity is 116,100 Bbls/d. Additionally, our operations include eight condensate stabilization and natural gas compression stations with combined capacities of over 36,000 Bbls/d of condensate stabilization and 780 MMcf/d of natural gas compression.

- *Corporate*. Our Corporate assets consist of a contractual right to the benefits and burdens associated with Devon's 38.75% ownership interest in Gulf Coast Fractionators ("GCF"), our approximate 31% ownership interest in Howard Energy Partners ("HEP") and our approximate 30% ownership in Cedar Cove Midstream LLC ("Cedar Cove JV").

About Devon

Devon (NYSE: DVN) is a leading independent energy company engaged primarily in the exploration, development and production of crude oil, natural gas and NGLs. Devon's operations are concentrated in various onshore areas in the U.S. and Canada. Please see Devon's Annual Report on Form 10-K for the year ended December 31, 2016 (the "Devon Annual Report") for additional information concerning Devon's business. The information contained in the Devon Annual Report is not incorporated by reference into this annual report on Form 10-K and should not be considered part of this or any other report that we file with or furnish to the SEC.

Our Business Strategies

Our primary business objective is to provide cash flow stability in our business while growing prudently and profitably. We intend to accomplish this objective by executing the following strategies:

- *Maintain stable cash flows supported by long-term, fee-based contracts.* We will seek to generate cash flows pursuant to long-term, firm contracts with creditworthy customers. We will continue to pursue opportunities to increase the fee-based and minimum volume commitment ("MVC") components of our contract portfolio to minimize our direct commodity price exposure.

- *Maintain a strong financial position.* We believe that maintaining a conservative and balanced capital structure, appropriate leverage and other key financial metrics will afford us better access to the capital markets at a competitive cost of capital. We also believe a strong financial position provides us the opportunity to grow our business in a prudent manner throughout the cycles in our industry.

- *Execute in our core growth areas.* We believe our assets are positioned in some of the most economic basins in the U.S., as well as key demand centers with growing end-use customers. We expect to grow certain of our systems organically over time by meeting our customers' midstream service needs that result from their drilling activity in our areas of operation. We continually evaluate whether to pursue economically attractive organic expansion opportunities in existing or new areas of operation that allow us to leverage our existing infrastructure, operating expertise and customer relationships by constructing and expanding systems to meet new or increased demand for our services.

Our Competitive Strengths

We believe that we are well-positioned to execute our strategies and to achieve our primary business objective due to the following competitive strengths:

- *Devon's sponsorship*. We expect our relationship with Devon will continue to provide us with significant business opportunities. Devon is one of the largest independent oil and gas producers in North America. Devon has a significant interest in promoting the success of our business, due to its 64.1% ownership interest in ENLC and 23.8% ownership interest in us as of December 31, 2016. Approximately 50% of our gross operating margin was attributable to commercial contracts with Devon in 2016.

- *Strategically-located assets*. The majority of our assets are strategically located in producing regions with the potential for increasing throughput volume and cash flow generation. Our asset portfolio includes gathering, transmission, fractionation, and processing systems that are located in the areas in which producer activity is focused on crude oil, condensate and NGLs, as well as natural gas. We have established platforms in Texas, Oklahoma, Louisiana and Ohio, and are focused on growing our operations in central Oklahoma, the Permian Basin and southern Louisiana through organic development and acquisitions.

- *Stable cash flows.* Approximately 97% of our cash flows were generated from fee-based services with no direct commodity exposure during 2016. We have approximately seven years remaining on fixed-fee gathering and processing agreements with a subsidiary of Devon pursuant to which we provide gathering, treating, compression, dehydration, stabilization, processing and fractionation services, as applicable, for natural gas delivered by Devon to our gathering and processing systems in the Barnett and Cana-Woodford Shales. These agreements provide us with dedication of all of the natural gas owned or controlled by Devon and produced from or attributable to existing and future wells located on certain oil, natural gas and mineral leases covering lands within the acreage dedications, excluding properties previously dedicated to other natural gas gathering systems not owned and operated by Devon. These agreements also include MVCs that will remain in effect through January 1, 2019, as well as annual rate escalators. Additionally, our recently acquired EnLink Oklahoma T.O. assets are supported by Devon with acreage dedications and MVCs for gathering and processing on Devon's Sooner Trend Anadarko Basin Canadian and Kingfisher Counties ("STACK") acreage. For additional information, please read "Our Contractual Relationship with Devon." We will continue to focus on contract structures that reduce volatility and support long-term stability of cash flows.

- *Integrated midstream services*. We span the energy value chain by providing natural gas, NGL, crude oil and condensate services across a diverse customer base. These services include gathering, compressing, treating, processing, transporting, storing and selling natural gas, producing, fractionating, transporting, storing, exporting and selling NGLs, and gathering, transporting, stabilizing, storing and trans-loading crude oil and condensate. We believe our ability to provide all of these services gives us an advantage in competing for new opportunities because we can provide substantially all services that producers, marketers and others require to move natural gas, NGLs, crude oil and condensate from the wellhead to the market on a cost-effective basis.

- *Experienced management team.* We believe our management team has a proven track record of creating value through the development, acquisition, optimization and integration of midstream assets. Our management team has an average of over 20 years of experience in the energy industry. We believe this team provides us with a strong foundation for evaluating growth opportunities and operating our assets in a safe, reliable and efficient manner.

We believe that we will leverage our competitive strengths to successfully implement our strategy; however, our business involves numerous risks and uncertainties that may prevent us from achieving our primary business objectives. For a more complete description of the risks associated with our business, please see "Item 1A. Risk Factors."

Our Contractual Relationship with Devon

The following table includes our long-term, fixed-fee contracts with Devon:

Contract	Contract Term (Years)	Year Contract Entered Into	Minimum Gathering Volume Commitment (MMcf/d)	Minimum Processing Volume Commitment (MMcf/d)	Minimum Volume Commitment Term (Years)	Annual Rate Escalators
Bridgeport gathering and processing contract (1)	10	2014	850	650	5	CPI
East Johnson County gathering contract	10	2014	125	—	5	CPI
Cana gathering and processing contract	10	2014	330	330	5	CPI
Central Oklahoma gathering and processing contract (2)	15	2016	Varies (2)	Varies (2)	5	—

(1) The Bridgeport gathering and processing contract includes volume commitments to the Bridgeport processing facility as well as the Bridgeport gathering systems.
(2) The minimum gathering volume commitments and minimum processing volume commitments under this contract escalate on a quarterly basis over the life of the five-year commitment, beginning with an average commitment of 37 MMcf/d during 2016 and ending with an average commitment of 230 MMcf/d during 2020.

In addition, we entered into to a five-year minimum transportation volume commitment with Devon related to our Victoria Express Pipeline ("VEX Pipeline"). The volume commitment under this contract escalates over the life of the contract, beginning with an average commitment of 25,000 Bbls/d during the first year and 30,000 Bbls/d in years two through five. The MVC was executed in June 2014, and the initial term expires in July 2019.

Recent Growth Developments

Acquisitions and Expansion

EnLink Oklahoma T.O. Acquisition and Expansion. On January 7, 2016, we and ENLC acquired an 84% and 16% interest, respectively, in EnLink Oklahoma T.O. for approximately $1.4 billion. The first installment of $1.02 billion for the acquisition was paid at closing. The second installment of $250.0 million was paid on January 6, 2017, and the final installment of $250.0 million is due no later than January 7, 2018. The installment payables are valued net of discount within the total purchase price.

The first installment consisted of approximately $1.02 billion and was funded by (a) approximately $783.6 million in cash paid by us, the majority of which was derived from the proceeds from the issuance of Preferred Units (as defined under "Issuance of Preferred Units" below), and (b) 15,564,009 common units representing limited liability company interests in ENLC issued directly by ENLC and approximately $22.2 million in cash paid by ENLC.

The EnLink Oklahoma T.O. assets serve gathering and processing needs in the growing STACK and Central Northern Oklahoma Woodford ("CNOW") plays in Oklahoma and are supported by long-term, fixed-fee contracts with acreage dedications that, at the time of acquisition, had a weighted-average term of approximately 15 years. The EnLink Oklahoma T.O. assets are strategically located in the core areas of the STACK and CNOW plays and include:

- *Chisholm Plant.* The Chisholm Plant, which serves the STACK play, is a cryogenic gas processing plant with a capacity of 120 MMcf/d. The plant is connected to a 350-mile, low- and high-pressure gathering system with compression facilities, including gathering pipelines and compression facilities completed by us during 2016.

  During 2016, we commenced construction on a new cryogenic gas processing plant, referred to as Chisholm II, that will provide an additional 200 MMcf/d of processing capacity and will be tied to new and existing pipelines in the STACK and South Central Oklahoma Oil Province ("SCOOP") play. Chisholm II is scheduled to be completed during the first quarter of 2017. The new capacity is supported by long-term contracts.

Additionally, we expect to commence construction on Chisholm III in April 2017. Chisholm III will provide an additional 200 MMcf/d of processing capacity and will be tied to new and existing pipelines in the STACK and SCOOP play. Construction is scheduled to be completed by the fourth quarter of 2017.

- *Battle Ridge Plant.* The Battle Ridge Plant is a cryogenic gas processing plant located in the CNOW play with a current capacity of 75 MMcf/d. The plant is connected to a 250-mile, low and high-pressure gathering system with compression facilities.

- *Connecting Pipeline.* A 42-mile, 16-inch high-pressure header pipeline with a total capacity of 150 MMcf/d was constructed to connect the Chisolm and Battle Ridge systems. The pipeline went into service in March 2016 and provides customers with additional operational flexibility.

Organic Growth

Greater Chickadee Crude Oil Gathering System. We have a new crude oil gathering system in Upton and Midland counties, Texas in the Permian Basin that we refer to as "Greater Chickadee." Greater Chickadee includes approximately 185 miles of high- and low-pressure pipelines that will transport crude oil volumes to several major market outlets and other key hub centers in the Midland, Texas area. Greater Chickadee also includes the construction of 50,000 Bbls of crude oil storage and a truck injection station to maximize shipping and delivery options for our producer customers. The initial phase of our Greater Chickadee transportation service began in November 2016. Additional construction is ongoing, and we expect full service capabilities in the first quarter of 2017.

Cedar Cove Joint Venture. On November 9, 2016, we formed the Cedar Cove JV with Kinder Morgan, Inc., consisting of gathering and compression assets in Blaine County, Oklahoma, located in the heart of the STACK play. The gathering system has a capacity of 25 MMcf/d with over 50,000 gross acres of dedications and ties into our existing Oklahoma assets. All gas gathered by the Cedar Cove JV will be processed at our central Oklahoma processing system (as defined below). We committed to contribute $39.0 million in cash in exchange for 30% ownership of the Cedar Cove JV, and as of December 31, 2016, we have contributed $28.8 million. Thereafter, we and Kinder Morgan, Inc. will contribute additional capital in proportion to our respective ownership interests to fund operations.

Delaware Basin Joint Venture. On August 1, 2016, we formed the Delaware Basin JV with NGP to operate and expand our natural gas, natural gas liquids and crude oil midstream assets in the liquids-rich Delaware Basin. The Delaware Basin JV is owned 50.1% by us and 49.9% by NGP. We contributed approximately $221.0 million of existing assets, net of depreciation, Basin JV and committed an additional $285.0 million in capital to fund potential future development projects and potential acquisitions. NGP committed an aggregate of approximately $400.0 million of capital, including an initial contribution of $114.3 million, which the Delaware Basin JV distributed to us at the formation of the joint venture to reimburse us for capital spent to the date of formation on existing assets and ongoing projects. In addition to the initial contributions, we and NGP contributed $30.2 million and $30.1 million, respectively, to the Delaware Basin JV for the year ended December 31, 2016. As part of this agreement, NGP granted us call rights beginning in 2021 to acquire increasing portions of NGP's interest in the joint venture at a price based upon a predetermined valuation methodology.

Lobo II Natural Gas Gathering and Processing Facility. In October 2016, we completed construction of a new cryogenic gas processing plant located in the Delaware Basin (our "Lobo II plant") with initial capacity of 60 MMcf/d. The Lobo II expansion also included the construction of a 75-mile gathering system located in Texas and New Mexico. Construction on the Texas portion of the gathering system was completed in October 2016, and the remaining New Mexico pipeline was completed in the first quarter of 2017. The Lobo II facilities are part of the Delaware Basin JV.

Riptide Processing Plant. In April 2016, we completed construction of the Riptide processing plant in the Permian Basin. The plant provides 100 MMcf/d of processing capacity and is tied to approximately 50 miles of new gathering pipeline, all of which is connected to our MEGA system (as defined below).

Ascension Joint Venture. We have formed a 50/50 joint venture named Ascension Pipeline Company, LLC (the "Ascension JV") with a subsidiary of Marathon Petroleum Corporation ("Marathon Petroleum") to build a new 30-mile NGL pipeline connecting our existing Riverside fractionation and terminal complex to Marathon Petroleum's Garyville refinery located on the Mississippi River. We commenced construction of the pipeline during 2016 and will operate the pipeline upon completion, which is currently estimated to be during the second quarter of 2017. This bolt-on project to our Cajun-Sibon NGL system is supported by long-term, fee-based contracts with Marathon Petroleum.

Sale of Non-Core Assets

In December 2016, we entered into an agreement to sell our ownership interest in HEP for approximately $193.1 million, subject to customary closing conditions, including regulatory approvals. We expect the transaction to close in the first quarter of 2017. For the year ended December 31, 2016, we recorded an impairment loss of $20.1 million to reduce the carrying value of our investment to the expected sales price.

In December 2016, we sold the North Texas Pipeline (the "NTPL"), a 140-mile natural gas transportation pipeline, for $84.6 million. We maintain capacity on the NTPL at competitive rates and at levels sufficient to support current and expected operations. We recorded a loss related to the sale of $13.4 million.

Acquisitions in 2014 and 2015:

- On November 1, 2014, we acquired, from affiliates of Chevron Corporation, Gulf Coast natural gas pipeline assets predominantly located in southern Louisiana, together with 100% of the voting interests in certain entities, for approximately $231.5 million.

- In 2014, we completed the drop down of certain equity interests in EnLink Appalachian Compression, LLC (formerly, E2 Appalachian Compression, LLC) and E2 Energy Services, LLC from ENLC.

- On January 31, 2015, we acquired 100% of the voting equity interests of LPC Crude Oil Marketing LLC ("LPC"), which has crude oil gathering, transportation and marketing operations in the Permian Basin, for approximately $108.1 million.

- On March 16, 2015, we acquired 100% of the voting equity interests in Coronado Midstream Holdings LLC ("Coronado"), which owns natural gas gathering and processing facilities in the Permian Basin, for approximately $600.3 million.

- On October 1, 2015, we acquired 100% of the voting equity interests in a subsidiary of Matador Resources Company ("Matador"), which has gathering and processing assets operations in the Delaware Basin, for approximately $141.3 million.

- Prior to November 2015, we co-owned the Deadwood natural gas processing plant with a subsidiary of Apache Corporation ("Apache"). On November 16, 2015, we acquired Apache's 50% ownership interest in the Deadwood natural gas processing facility for approximately $40.1 million. We now own 100% of the Deadwood processing plant.

- In 2015, we completed the EMH Drop Downs and a drop down transaction to acquire VEX from Devon.

Our Assets

Our assets consist of gathering systems, transmission pipelines, processing facilities, fractionation facilities, stabilization facilities, storage facilities and ancillary assets. Except as stated otherwise, the following tables provide information about our assets as of and for the year ended December 31, 2016:

Gathering and Transmission Pipelines	Approximate Length (Miles)	Compression (1) (HP)	Estimated Capacity (2)	Year Ended December 31, 2016 Average Throughput (3)
Gas Pipelines				
Texas Assets:				
North Texas Assets (4)	3,980	341,600	2,892	2,377,300
Permian Basin Assets (5)	520	73,760	348	245,100
Oklahoma Assets:				
Central Oklahoma System	1,040	206,000	745	585,200
Northridge System	140	14,000	65	44,300
Louisiana Assets:				
Louisiana Gas System	3,145	97,400	3,975	1,676,500
Total Gas Pipelines	8,825	732,760	8,025	4,928,400
NGL, Crude Oil and Condensate Pipelines				
Louisiana Assets:				
Louisiana Liquids Pipeline System	720	—	130,000	104,900
Crude and Condensate Assets:				
Ohio River Valley (6)	210	—	25,650	19,900
Victoria Express Pipeline	60	—	90,000	14,500
Permian Gathering (7)	270	—	85,800	55,500
Total NGL, Crude Oil and Condensate Pipelines	1,260	—	331,450	194,800

(1) Includes power generation units.
(2) Estimated capacity for gas pipelines is MMcf/d. Estimated capacity for liquids and crude and condensate pipelines is Bbls/d.
(3) Average throughput for gas pipelines is MMBtu/d. Average throughput for liquids and crude and condensate pipelines is Bbls/d.
(4) Includes throughput volumes of 256,700 MMbtu/d for the North Texas Pipeline, which was sold in December 2016.
(5) Includes gross mileage, compression, capacity and throughput for the Delaware Basin JV, which is owned 50.1% by us.
(6) Estimated capacity is comprised of trucking capacity only.
(7) Estimated capacity is comprised of 26,100 Bbls/d of pipeline capacity and 59,700 Bbls/d of trucking capacity.

Processing Facilities	Processing Capacity (MMcf/d)	Year Ended December 31, 2016 Average Throughput (MMBtu/d)
Texas Assets:		
North Texas Assets	1,080	890,900
Permian Basin Assets	503	282,300
Oklahoma Assets:		
Central Oklahoma System	595	522,700
Northridge System	200	54,900
Louisiana Assets:		
Louisiana Gas System	1,903	490,400
Total	4,281	2,241,200

Fractionation Facilities	Estimated NGL Fractionation Capacity (MBbls/d)	Year Ended December 31, 2016 Average Throughput (MBbls/d)
Louisiana Liquids System	175	124
Gulf Coast Fractionators (1)	56	38
Texas Assets	30	— (2)
Total	261	162

(1) Volumes shown reflect only our contractual right to the burdens and benefits of a 38.75% economic interest in Gulf Coast Fractionators held by Devon.
(2) We have two small fractionation facilities of 15 MBbls/d each. Our Mesquite Terminal in the Permian Basin and our Bridgeport processing plant in North Texas provide operational flexibility for the related processing plants, but are not the primary fractionation facilities for the NGLs produced by the processing plants. Under our current contracts, we do not earn fractionation fees for operating these facilities, so throughput volumes through these facilities are not captured on a routine basis and are not significant to our operating margins.

Texas Assets. Our Texas assets include transmission pipelines with a capacity of approximately 920 MMcf/d, processing facilities with a total processing capacity of approximately 1.6 Bcf/d and gathering systems with a capacity of approximately 2.3 Bcf/d.

- Transmission System. The Acacia transmission system is a 130-mile pipeline that connects production from the Barnett Shale to markets in north Texas accessed by Atmos Energy, Brazos Electric, Midcoast Energy Partners, Energy Transfer Partners, Enterprise Product Partners and GDF Suez. The Acacia transmission system has approximately 920 MMcf/d of capacity and 16,600 horsepower of compression and, for the year ended December 31, 2016, average throughput was approximately 615,100 MMBtu/d. Devon is the Acacia transmission system's only customer with approximately seven years remaining on a fixed-fee transportation agreement that covers transmission services and includes annual rate escalators.

- Processing and Fractionation Facilities. Our processing facilities in Texas include 10 gas processing plants and our 38.75% interest in GCF and consist of the following:

  - *North Texas Assets.* Our North Texas processing systems include the following:

    - *Bridgeport processing facility.* Our Bridgeport natural gas processing facility, located in Wise County, Texas, approximately 40 miles northwest of Fort Worth, Texas, is one of the largest processing plants in the U.S. with seven cryogenic turboexpander plants that have a total of 800 MMcf/d of processing capacity and 15 MBbls/d of NGL fractionation capacity. For the year ended December 31, 2016, throughput volumes at the Bridgeport processing facility averaged 662,000 MMBtu/d of natural gas. Devon is the Bridgeport facility's largest customer with approximately 656,700 MMBtu/d of natural gas processed for the year ended December 31, 2016. We currently have approximately seven years remaining on a fixed-fee processing agreement with Devon pursuant to which we provide processing services for natural gas delivered by Devon to the Bridgeport processing facility. This contractual arrangement includes an MVC from Devon of 650 MMcf/d of natural gas delivered to the Bridgeport processing facility that will remain in effect through January 1, 2019 and also provides annual rate escalators.

    - *Silver Creek processing complex*. Our Silver Creek processing complex, located in Weatherford, Azle and Fort Worth, Texas, includes three processing plants. Our Silver Creek plants have a total of 280 MMcf/d of processing capacity, with the Azle Plant, Silver Creek Plant and Goforth Plant accounting for 50 MMcf/d, 200 MMcf/d and 30 MMcf/d of processing capacity, respectively. For the year ended December 31, 2016, throughput volumes at the Silver Creek processing facility averaged 228,900 MMBtu/d of natural gas.

- *Permian Basin assets*. Our Permian Basin processing facilities consist of the following:

  - *MEGA system processing facilities.* Our Permian Basin processing plants are located in Midland, Martin, and Glasscock counties, and operate as a connected system. These assets consist of the Bearkat processing facility with a capacity of 75 MMcf/d, the Deadwood processing facility with a capacity of 58 MMcf/d, the Midmar processing facilities with a capacity of 175 MMcf/d and the Riptide processing facility with a capacity of 100 MMcf/d (collectively, the “Midland Energy Gathering Area” or “MEGA system”). For the year ended December 31, 2016, throughput volumes at the MEGA system averaged 258,000 MMBtu/d of natural gas.

  - *Lobo processing facility*. Our Lobo natural gas processing facility is located in Loving County, Texas and has a total capacity of 95 MMcf/d. For the year ended December 31, 2016, throughput volumes at the Lobo facility averaged 24,300 MMBtu/d of natural gas. The Lobo Processing facility was contributed to the Delaware Basin JV on August 1, 2016.

- Gathering Systems. Our gathering systems in Texas include approximately 4,400 miles of pipeline.

  - *North Texas Assets.* Our North Texas gathering systems include the following:

    - *Bridgeport rich gathering system.* This rich natural gas gathering system consists of approximately 2,240 miles of pipeline segments with approximately 145,000 horsepower of compression. A substantial majority of the natural gas gathered on the system is delivered to the Bridgeport processing facility. For the year ended December 31, 2016, throughput volumes on the Bridgeport rich gathering system averaged 685,200 MMBtu/d of natural gas. Devon is the largest customer on the Bridgeport rich gathering system with approximately 659,300 MMBtu/d of natural gas gathered for the year ended December 31, 2016. As described above, we currently have approximately seven years remaining on a fixed-fee gathering agreement with Devon pursuant to which we provide gathering services on the Bridgeport system, and the agreement includes an MVC from Devon that will remain in effect through January 1, 2019, with a combined 850 MMcf/d of natural gas to be delivered for gathering into the Bridgeport rich and Bridgeport lean gathering systems.

    - *Bridgeport lean gathering system.* This lean natural gas gathering system consists of approximately 600 miles of pipeline segments with approximately 59,000 horsepower of compression. Natural gas gathered on this system is delivered to the Acacia transmission system and intrastate pipelines without processing. For the year ended December 31, 2016, throughput volumes on the Bridgeport lean gathering system averaged 216,600 MMBtu/d of natural gas, all of which were attributable to Devon. As described above, we are party to a fixed-fee gathering and processing agreement with Devon that covers gathering services on the Bridgeport system.

    - *Johnson County gathering system*. This natural gas gathering system consists of approximately 290 miles of pipeline segments with approximately 44,000 horsepower of compression. Natural gas gathered on this system is delivered to intrastate pipelines without processing. For the year ended December 31, 2016, throughput volumes on the Johnson County gathering system averaged 143,200 MMBtu/d of natural gas, which were primarily attributable to Devon. We currently have approximately seven years remaining on a fixed-fee gathering agreement pursuant to which we provide gathering services on the Johnson County gathering system. This contractual arrangement includes an MVC from Devon that will remain in effect through January 1, 2019, with 125 MMcf/d of natural gas to be delivered for gathering into the Johnson County gathering system and also provides annual rate escalators.

    - *Silver Creek gathering systems*. Our Silver Creek gathering system consists of approximately 720 miles of gathering lines with approximately 77,000 horsepower of compression and had an average throughput of approximately 460,500 MMBtu/d for the year ended December 31, 2016.

- *Permian Basin assets*. Our Permian Basin gathering systems include the following:

  - *MEGA system gathering facilities*. Our gathering system in the Permian Basin consists of the 140-mile Bearkat gathering system with 19,000 horsepower of compression, and the 300-mile Midland Basin gathering system with 52,000 horsepower of compression. For the year ended December 31, 2016 throughput averaged 220,900 MMBtu/d.

  - *Lobo gathering system.* The rich natural gas gathering system consists of 80 miles of gathering pipeline with approximately 2,760 horsepower of compression. For the year ended December 31, 2016, throughput volumes averaged 24,200 MMBtu/d. The Lobo gathering system was contributed to the Delaware Basin JV on August 1, 2016.

Oklahoma Assets. Our Oklahoma assets consist of processing facilities with a total processing capacity of approximately 795 MMcf/d and gathering systems with total capacity of approximately 810 MMcf/d.

- Oklahoma processing system. Our processing facilities include the following:

  - *Central Oklahoma processing system.* The central Oklahoma plants include the 120 MMcf/d Chisholm plant, the 75 MMcf/d Battle Ridge plant and the 400 MMcf/d Cana processing facilities (collectively, the "central Oklahoma processing system"). The residue natural gas from the Cana processing facility is delivered to Enable Midstream Partners and ONEOK Partners. Devon is the primary customer of the Cana processing facilities and has approximately seven years remaining on a fixed-fee gathering and processing agreement with us pursuant to which we provide processing services for natural gas delivered by Devon to the Cana processing facility. Throughput for the central Oklahoma processing system for the year ended December 31, 2016 averaged 522,700 MMBtu/d. In addition, contractual arrangements related to the central Oklahoma processing system that contain an MVC include the following:

    - Our contractual arrangement with Devon includes an MVC that escalates quarterly and will remain in effect until October 2020. For 2017, the MVC dictates that approximately 103 MMcf/d of natural gas will be delivered to the Chisholm plant processing facility. The MVC escalates quarterly, resulting in approximately 230 MMcf/d to be delivered in 2020. The contractual arrangement also provides annual rate escalators.

    - We have another contractual arrangement with Devon that includes an MVC that will remain in effect until January 1, 2019, with 330 MMcf/d of natural gas to be delivered to the Cana processing facility, and provides annual rate escalators.

  - *Northridge processing plant.* Our Northridge processing plant has 200 MMcf/d of processing capacity. For the year ended December 31, 2016, throughput volumes at the Northridge processing facility averaged 54,900 MMBtu/d. The residue natural gas from the Northridge processing facility is delivered to Centerpoint, Enable Midstream Partners and MarkWest.

- Oklahoma gathering system. Our Oklahoma gathering systems include the following:

  - *Central Oklahoma gathering system.* Our central Oklahoma gathering system consists of the 350-mile Chisholm gathering system with approximately 80,000 horsepower of compression, the 250-mile Battle Ridge gathering system with approximately 38,000 horsepower of compression and the 440-mile Cana gathering system with approximately 88,000 horsepower of compression (collectively, the "central Oklahoma gathering system"). The central Oklahoma gathering system serves the STACK and CNOW plays. For the year ended December 31, 2016, throughput averaged 585,200 MMbtu/d. In addition, contractual arrangements related to the central Oklahoma gathering system that contain an MVC include the following:

    - Our contractual arrangement with Devon includes an MVC that will remain in effect until October 2020. For 2017, the MVC dictates that approximately 103 MMcf/d of natural gas will be handled through the Chisholm gathering system. The MVC escalates quarterly, resulting in approximately 230 MMcf/d to be delivered in 2020. The contractual arrangement also provides annual rate escalators.

- We have another contractual arrangement with Devon that includes an MVC that will remain in effect until January 1, 2019, with 330 MMcf/d of natural gas to be handled through the Cana gathering system, and provides annual rate escalators.

· *Northridge gathering system.* Our Northridge gathering system is located in the Arkoma-Woodford Shale in Southeastern Oklahoma and includes an approximately 140-mile gathering system with approximately 14,000 horsepower of compression. For the year ended December 31, 2016, the Northridge system gathered 44,300 MMBtu/d of gas.

Louisiana Assets. Our Louisiana assets consist of transmission pipelines with a capacity of approximately 3.5 Bcf/d, processing facilities with a total processing capacity of approximately 1.9 Bcf/d and gathering systems with total capacity of approximately 510 MMcf/d.

· Louisiana Gas Pipeline and Processing Systems. The Louisiana gas pipeline system includes gathering and transmission systems with a capacity of approximately 4.0 Bcf/d and processing facilities with total processing capacity of approximately 1.9 Bcf/d and underground gas storage of 19.2 Bcf/d

· *Gas Gathering and Transmission Systems.* Our gathering and transmission systems include 3,145 miles of gathering and transmission systems with a total capacity of 4.0 bcf/d. The systems have a combined 97,400 horsepower of compression. The system has access to both rich and lean gas supplies from onshore production in south central and southeast Louisiana and a variety of transportation and industrial sale customers in south Louisiana, with the majority of its sales being made into the industrial Mississippi River corridor between Baton Rouge and New Orleans. This system also serves the natural gas fields south of Shreveport, Louisiana and extends into the Haynesville Shale plays in north Louisiana. For the year ended December 31, 2016, throughput volumes on the gathering system averaged 671,500 MMBtu/d of natural gas, and throughput volumes on the transmission system averaged 1,005,000 MMBtu/d of natural gas.

· *Gas Processing and Storage Facilities.* Our processing facilities in Louisiana include five gas processing plants, of which three are currently operational, with total processing throughput that averaged 490,400 MMBtu/d for the year ended December 31, 2016.

· *Plaquemine Processing Plant.* The Plaquemine processing plant has 225 MMcf/d of processing capacity. For the year ended December 31, 2016, throughput volumes of the Plaquemine processing plant averaged 156,000 MMBtu/d of natural gas.

· *Gibson Processing Plant.* The Gibson processing plant has 110 MMcf/d of processing capacity. For the year ended December 31, 2016, throughput volumes of the Gibson processing plant averaged 41,000 MMBtu/d of natural gas.

· *Pelican Processing Plant*. The Pelican processing plant complex is located in Patterson, Louisiana and has a designed capacity of 600 MMcf/d of natural gas. For the year ended December 31, 2016, the plant processed approximately 293,400 MMBtu/d of natural gas. The Pelican plant is connected with continental shelf and deepwater production and has downstream connections to the ANR Pipeline. This plant has an interconnection with the Louisiana gas pipeline system allowing us to process natural gas from this system at our Pelican plant when markets are favorable.

· *Blue Water Gas Processing Plant.* We operate and own a 64.29% interest in the Blue Water gas processing plant. The Blue Water plant is located in Crowley, Louisiana and is connected to the Blue Water pipeline system. Our share of the plant's capacity is approximately 193 MMcf/d. The plant is not expected to operate in the future unless fractionation spreads are favorable and volumes are sufficient to run the plant.

- *Eunice Processing Plant.* The Eunice processing plant is located in south central Louisiana and has a capacity of 475 MMcf/d of natural gas. In August 2013, we shut down the Eunice processing plant due to adverse economics driven by low NGL prices and low processing volumes, which we do not see improving in the near future based on forecasted prices.

- *Belle Rose Gas Storage Facility.* The Belle Rose storage facility is located in Assumption Parish, Louisiana and has a total capacity of 11.9 Bcf. This facility was placed in service in May 2016 and is designed for injecting pipeline quality gas into storage or withdrawing stored gas for delivery by pipeline. The storage facility includes three compressors with a total of 9,637 horsepower.

- *Sorrento Gas Storage Facility.* The storage facility is located in Assumption Parish, Louisiana and has a total capacity of 7.3 Bcf. This facility is designed for injecting pipeline quality gas into storage or withdrawing stored gas for delivery by pipeline. There are three compressors with a total of 6,600 horsepower.

- Louisiana Liquids Pipeline System. Our Louisiana liquids pipeline system includes approximately 720 miles of liquids transport lines, processing and fractionation assets and underground storage.

- *Cajun-Sibon Pipeline System.* The Cajun-Sibon pipeline system consists of approximately 720 miles of raw make NGL pipelines with a current system capacity of approximately 130,000 Bbls/d. For the year ended December 31, 2016, average throughput was approximately 104,900 MMBtu/d. The pipelines transport unfractionated NGLs, referred to as "raw make," from areas such as the Liberty, Texas interconnects near Mont Belvieu and from our Eunice and Pelican processing plants in south Louisiana to either the Riverside or Eunice fractionators or to third party fractionators when necessary.

- *Fractionation Facilities.* There are four fractionation facilities located in Louisiana that averaged 123,700 Bbls/d for the year ended December 31, 2016.

- *Plaquemine Fractionation Facility.* The Plaquemine fractionator is located at our Plaquemine gas processing plant complex and is connected to our Cajun-Sibon pipeline. The Plaquemine fractionation facility produces purity ethane and propane for sale by pipeline to long-term markets with the butane and heavier products sent to our Riverside facility for further processing. The Plaquemine fractionator collectively with the Riverside Fractionation Facility has an approximate capacity of 110,000 Bbls/d of raw-make NGL products. The Plaquemine facility fractionated 55,400 Bbls/d for the year ended December 31, 2016.

- *The Plaquemine Gas Processing Plant.* The Plaquemine Gas Processing Plant also has a fractionator with a capacity of 11,000 Bbls/d of raw-make NGL products, and total volume for fractionated liquids at Plaquemine averaged approximately 3,600 Bbls/d for the year ended December 31, 2016.

- *Eunice Fractionation Facility.* The Eunice fractionation facility is located in south central Louisiana. The Eunice fractionation facility has a capacity of 55,000 Bbls/d of liquid products, including ethane, propane, iso-butane, normal butane and natural gasoline, and is directly connected to the southeast propane market and pipelines to the Anse La Butte storage facility. The plant fractionated 36,600 Bbls/d of liquids for the year ended December 31, 2016.

- *Riverside Fractionation Facility.* The Riverside fractionator and loading facility is located on the Mississippi River upriver from Geismar, Louisiana. The Riverside plant has a fractionation capacity of approximately 32,000 Bbls/d of liquids delivered by the Cajun-Sibon pipeline system from the Eunice and Pelican processing plants or by third-party truck and rail assets. The Riverside facility has above-ground storage capacity of approximately 278,300 Bbls. The loading/unloading facility has the capacity to transload 15,000 Bbls/d of crude oil and condensate from rail cars to barges. Total volumes for fractionated liquids at Riverside averaged 28,100 Bbls/d for the year ended December 31, 2016.

- *Napoleonville Storage Facility.* The Napoleonville NGL storage facility is connected to the Riverside facility and has a total capacity of 3.2 million barrels of underground storage comprised of two existing caverns. The caverns are currently operated in butane service, and space is leased to customers for a fee.

Crude and Condensate. Our Crude and Condensate assets consist of approximately 540 miles of crude oil and condensate pipelines. The assets also include 900,000 barrels of above ground storage and a trucking fleet of approximately 150 vehicles comprised of both semi and straight trucks with a current capacity of 85,350 Bbls/d. The current pipeline capacity is 116,100 Bbls/d. Additionally, our operations include eight condensate stabilization and natural gas compression stations with combined capacities of over 36,000 Bbls/d of condensate stabilization and 780 MMcf/d of natural gas compression.

- *Ohio River Valley.* Our Ohio River Valley ("ORV") operations are an integrated network of assets comprised of a 5,000-barrel-per-hour crude oil and condensate barge loading terminal on the Ohio River, a 20-spot crude oil and condensate rail loading terminal on the Ohio Central Railroad network and approximately 210 miles of crude oil and condensate pipelines in Ohio and West Virginia. The assets also include over 500,000 barrels of above ground storage and a trucking fleet of approximately 86 vehicles comprised of both semi and straight trucks, and trailers for hauling NGL volumes with a current capacity of 25,650 Bbls/d. Total crude oil and condensate handled averaged approximately 19,900 Bbls/d for the year ended December 31, 2016. We have eight existing brine disposal wells with an injection capacity of approximately 4,000 Bbls/d and an average disposal rate of 3,600 Bbls/d for the year ended December 31, 2016. Additionally, our ORV operations include eight condensate stabilization and natural gas compression stations with combined capacities of over 36,000 Bbls/d of condensate stabilization and 780 MMcf/d of natural gas compression. These stations are in service and are supported by long-term, fee-based contracts with multiple producers.

- *Permian Crude and Condensate.* Our Permian Crude and Condensate assets have crude oil gathering, transportation and marketing operations in the Permian Basin with a current capacity of approximately 85,800 Bbls/d. Their integrated logistics services are supported by 54 tractor trailers, 14 pipeline injection stations and 85 miles of crude oil gathering pipeline. Total crude oil and condensate handled averaged approximately 54,500 Bbls/d for the year ended December 31, 2016.

  Additionally we have a new crude oil gathering system in Upton and Midland counties, Texas in the Permian Basin that we refer to as "Greater Chickadee." Greater Chickadee includes approximately 185 miles of high- and low-pressure pipelines that will transport crude oil volumes to several major market outlets and other key hub centers in the Midland, Texas area. Greater Chickadee also includes the construction of multiple central tank batteries and pump, truck injection, and storage stations to maximize shipping and delivery options for our producer customers. The initial phase of our Greater Chickadee transportation service began in November 2016. For the year ended December 31, 2016, throughput volumes averaged 1,000 Bbls/d. For the period of commencement of service to December 31, 2016, throughput volumes averaged 6,200 Bbls/d. Additional construction is ongoing, and we expect the gathering system to reach full service in the first quarter of 2017.

- *Victoria Express Pipeline.* The VEX pipeline is a 60-mile, multi-grade crude oil pipeline with a current capacity of approximately 90,000 Bbls/d. Other VEX assets include the Cuero Terminal and Port of Victoria Terminal and Barge Docks. The Cuero truck unloading terminal at the origin of the VEX system contains 8 unloading bays and 200,000 bbls of above-ground storage capacity for receipt from and delivery to the VEX pipeline. The VEX pipeline terminates at the Port of Victoria Terminal that also has an 8-bay truck unloading dock and 200,000 bbls of above-ground storage capacity. The Port of Victoria Terminal delivers to two barge loading docks at the Port of Victoria. Total crude oil and condensate handled averaged approximately 14,500 Bbls/d for the year ended December 31, 2016. We have an agreement with Devon, which includes an MVC of 30,000 Bbls/d, that will remain in effect until July 2019.

Corporate. Our Corporate assets primarily consist of a contractual right to the benefits and burdens associated with Devon's 38.75% ownership interest in GCF, an approximate 31% ownership interest in HEP and a 30% ownership interest in the Cedar Cove Joint Venture.

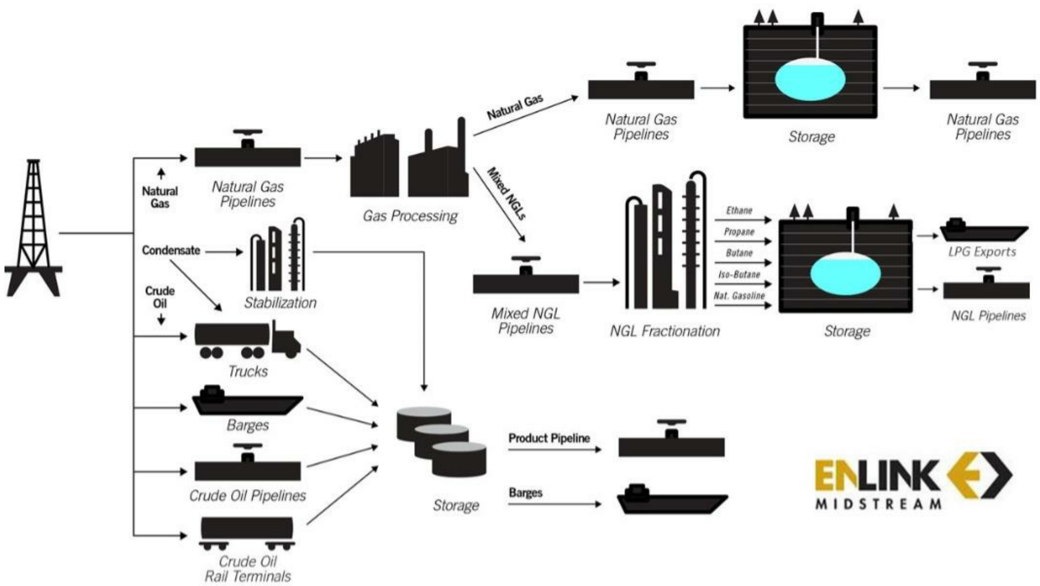
· *Gulf Coast Fractionators.* We are entitled to receive the economic benefits and burdens of the 38.75% interest in GCF held by Devon, with the remaining interests owned 22.5% by Phillips 66 and 38.75% by Targa Resources Partners. GCF owns an NGL fractionator located on the Gulf Coast at Mont Belvieu, Texas. Phillips 66 is the operator of the fractionator. GCF receives raw mix NGLs from customers, fractionates the raw mix and redelivers the finished products to the customers for a fee. The facility has a capacity of approximately 145 MBbls/d. The plant fractionated approximately 38,000 Bbls/d of liquids for the year ended December 31, 2016.

· *Howard Energy Partners* As of December 31, 2016, we owned an approximate 31% interest in HEP and accounted for this investment under the equity method of accounting. In December 2016, we entered into an agreement to sell our ownership in HEP to Alberta Investment Corp for approximately $193.1 million. The transaction is expected to close during the first quarter of 2017.

· *Cedar Cove Joint Venture.* On November 9, 2016, we formed a joint venture with Kinder Morgan, Inc. consisting of gathering and compression assets in Blaine County, Oklahoma. The gathering system has a capacity of 25 MMcf/d and ties into our existing Oklahoma assets. All gas gathered by Cedar Cove will be processed at our central Oklahoma plants.

Industry Overview

The following diagram illustrates the gathering, processing, fractionation, stabilization and transmission process.



The midstream industry is the link between the exploration and production of natural gas and crude oil and condensate and the delivery of its components to end-user markets. The midstream industry is generally characterized by regional competition based on the proximity of gathering systems and processing plants to natural gas and crude oil and condensate producing wells.

Natural gas gathering. The natural gas gathering process follows the drilling of wells into gas-bearing rock formations. After a well has been completed, it is connected to a gathering system. Gathering systems typically consist of a network of small diameter pipelines and, if necessary, compression and treating systems that collect natural gas from points near producing wells and transport it to larger pipelines for further transmission.

Compression. Gathering systems are operated at pressures that will maximize the total natural gas throughput from all connected wells. Because wells produce gas at progressively lower field pressures as they age, it becomes increasingly difficult to deliver the remaining production in the ground against the higher pressure that exists in the connected gathering system. Natural gas compression is a mechanical process in which a volume of gas at an existing pressure is compressed to a desired higher pressure, allowing gas that no longer naturally flows into a higher-pressure downstream pipeline to be brought to market. Field compression is typically used to allow a gathering system to operate at a lower pressure or provide sufficient discharge pressure to deliver gas into a higher-pressure downstream pipeline. The remaining natural gas in the ground will not be produced if field compression is not installed because the gas will be unable to overcome the higher gathering system pressure. A declining well can continue delivering natural gas if field compression is installed.

Natural gas processing. The principal components of natural gas are methane and ethane, but most natural gas also contains varying amounts of heavier NGLs and contaminants, such as water and CO_2, sulfur compounds, nitrogen or helium. Natural gas produced by a well may not be suitable for long-haul pipeline transportation or commercial use and may need to be processed to remove the heavier hydrocarbon components and contaminants. Natural gas in commercial distribution systems mostly consists of methane and ethane, and moisture and other contaminants have been removed so there are negligible amounts of them in the gas stream. Natural gas is processed to remove unwanted contaminants that would interfere with pipeline transportation or use of the natural gas and to separate those hydrocarbon liquids from the gas that have higher value as NGLs. The removal and separation of individual hydrocarbons through processing is possible due to differences in weight, boiling point, vapor pressure and other physical characteristics. Natural gas processing involves the separation of natural gas into pipeline-quality natural gas and a mixed NGL stream and the removal of contaminants.

NGL fractionation. NGLs are separated into individual, more valuable components during the fractionation process. NGL fractionation facilities separate mixed NGL streams into discrete NGL products: ethane, propane, isobutane, normal butane, natural gasoline and stabilized crude oil and condensate. Ethane is primarily used in the petrochemical industry as feedstock for ethylene, one of the basic building blocks for a wide range of plastics and other chemical products. Propane is used as a petrochemical feedstock in the production of ethylene and propylene and as a heating fuel, an engine fuel and industrial fuel. Isobutane is used principally to enhance the octane content of motor gasoline. Normal butane is used as a petrochemical feedstock in the production of ethylene and butylene (a key ingredient in synthetic rubber), as a blend stock for motor gasoline and to derive isobutene through isomerization. Natural gasoline, a mixture of pentanes and heavier hydrocarbons, is used primarily as motor gasoline blend stock or petrochemical feedstock.

Natural gas transmission. Natural gas transmission pipelines receive natural gas from mainline transmission pipelines, processing plants and gathering systems and deliver it to industrial end-users, utilities and to other pipelines.

Crude oil and condensate transmission. Crude oil and condensate are transported by pipelines, barges, rail cars and tank trucks. The method of transportation used depends on, among other things, the resources of the transporter, the locations of the production points and the delivery points, cost-efficiency and the quantity of product being transported.

Condensate Stabilization. Condensate stabilization is the distillation of the condensate product to remove the lighter end components, which ultimately creates a higher quality condensate product that is then delivered via truck, rail or pipeline to local markets.

Brine gathering and disposal services. Typically, shale wells produce significant amounts of water that, in most cases, require disposal. Produced water and frac-flowback is hauled via truck transport or is pumped through pipelines from its origin at the oilfield tank battery or drilling pad to the disposal location. Once the water reaches the delivery disposal location, water is processed and filtered to remove impurities and injection wells place fluids underground for storage and disposal.

Crude oil and condensate terminals. Crude oil and condensate rail terminals are an integral part of ensuring the movement of new crude oil and condensate production from the developing shale plays in the United States and Canada.

In general, the crude oil and condensate rail loading terminals are used to load rail cars and transport the commodity out of developing basins into market rich areas of the country where crude oil and condensate rail unloading terminals are used to unload rail cars and store crude oil and condensate volumes for third parties until the crude oil and condensate is redelivered to premium market delivery points via pipelines, trucks or rail.

Balancing Supply and Demand

When we purchase natural gas, crude oil and condensate, we establish a margin normally by selling it for physical delivery to third-party users. We can also use over-the-counter derivative instruments or enter into future delivery obligations under futures contracts on the New York Mercantile Exchange (NYMEX) related to our natural gas purchases. Through these transactions, we seek to maintain a position that is balanced between (1) purchases and (2) sales or future delivery obligations. Our policy is not to acquire and hold natural gas futures contracts or derivative products for the purpose of speculating on price changes.

Competition

The business of providing gathering, transmission, processing and marketing services for natural gas, NGLs, crude oil and condensate is highly competitive. We face strong competition in obtaining natural gas, NGLs, crude oil and condensate supplies and in the marketing and transportation of natural gas, NGLs, crude oil and condensate. Our competitors include major integrated and independent exploration and production companies, natural gas producers, interstate and intrastate pipelines, other natural gas, NGLs and crude oil and condensate gatherers and natural gas processors. Competition for natural gas and crude oil and condensate supplies is primarily based on geographic location of facilities in relation to production or markets, the reputation, efficiency and reliability of the gatherer and the pricing arrangements offered by the gatherer. As a result of certain of our contractual relationships with Devon, we will not compete for the portion of Devon's existing operations subject to existing acreage dedication for the terms of such contracts. For areas where acreage is not dedicated to us, we will compete with similar enterprises in providing additional gathering and processing services in its respective areas of operation, which may offer more services or have strong financial resources and access to larger natural gas, NGLs, crude oil and condensate supplies than we do. Our competition varies in different geographic areas.

In marketing natural gas, NGLs, crude oil and condensate, we have numerous competitors, including marketing affiliates of interstate pipelines, major integrated oil and gas companies, and local and national natural gas producers, gatherers, brokers and marketers of widely varying sizes, financial resources and experience. Local utilities and distributors of natural gas are, in some cases, engaged directly and through affiliates in marketing activities that compete with our marketing operations.

We face strong competition for acquisitions and development of new projects from both established and start-up companies. Competition increases the cost to acquire existing facilities or businesses and results in fewer commitments and lower returns for new pipelines or other development projects. Our competitors may have greater financial resources than we possess or may be willing to accept lower returns or greater risks. Our competition differs by region and by the nature of the business or the project involved.

Natural Gas, NGL, Crude Oil and Condensate Supply

Our gathering and transmission pipelines have connections with major intrastate and interstate pipelines, which we believe have ample natural gas and NGL supplies in excess of the volumes required for the operation of these systems. We evaluate well and reservoir data that is either publicly available or furnished by producers or other service providers in connection with the construction and acquisition of our gathering systems and assets to determine the availability of natural gas, NGLs, crude oil and condensate supply for our systems and assets and/or obtain an MVC from the producer that results in a rate of return on investment. We do not routinely obtain independent evaluations of reserves dedicated to our systems and assets due to the cost and relatively limited benefit of such evaluations. Accordingly, we do not have estimates of total reserves dedicated to our systems and assets or the anticipated life of such producing reserves.

Credit Risk and Significant Customers

We are subject to risk of loss resulting from nonpayment or nonperformance by our customers and other counterparties, such as our lenders and hedging counterparties. We diligently attempt to ensure that we issue credit to only credit-worthy customers. However, our purchase and resale of crude oil, condensate, NGLs and natural gas exposes us to significant credit risk, as the margin on any sale is generally a very small percentage of the total sales price. Therefore, a credit loss can be very large relative to our overall profitability. Some of our customers have filed for bankruptcy protection, and their debts and payments to us are subject to laws governing bankruptcy. Moreover, the combination of a reduction of cash flow resulting from lower commodity prices, a reduction in borrowing bases under reserve-based credit facilities and the lack of availability of debt or equity financing may result in a significant reduction in our customers' liquidity and 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. A substantial portion of our throughput volumes come from producers that have investment-grade ratings; however, many of our customers' equity values have substantially declined and some of these customers, including Devon, have had their credit ratings downgraded by major credit ratings agencies.

For the years ended December 31, 2016, 2015 and 2014, Devon represented 18.5%, 16.6% and 30.6%, respectively, of our consolidated revenues and Dow Hydrocarbons & Resources LLC ("Dow Hydrocarbons") represented 10.8%, 11.7% and 11.0%, respectively, of our consolidated revenues. No other customer represented greater than 10.0% of our revenue. Our operations are dependent on the volume of natural gas that Devon provides to us under commercial agreements, which constitutes a substantial portion of our natural gas supply. The loss of Devon or Dow Hydrocarbons as a customer could have a material impact on our results of operations if we were not able to sell our products to another customer with similar margins because the gross operating margins received from transactions with Devon and Dow Hydrocarbons are material to our total gross operating margin.

Regulation

Interstate Natural Gas Pipeline Regulation. We own interstate natural gas pipelines that are subject to regulation as natural gas companies by the Federal Energy Regulatory Commission ("FERC") under the Natural Gas Act ("NGA"). These assets include our Acacia transmission system and our Louisiana gas pipeline system. FERC regulates the rates and terms and conditions of service on interstate natural gas pipelines, as well as the certification, construction, extension and abandonment of facilities.

The rates and terms and conditions for our interstate pipeline services must be just and reasonable and not unduly preferential or unduly discriminatory, although negotiated or settlement rates may be accepted in certain circumstances. Such rates and terms and conditions are set forth in FERC-approved tariffs. FERC must approve proposed rate increases and changes to our tariffs. Pursuant to FERC's jurisdiction over rates, existing rates may be challenged by complaint or by FERC on its own initiative, and proposed rate increases may be challenged by protest. If protested, a rate increase may be suspended for up to five months and collected, subject to refund. If, upon completion of an investigation, FERC finds that the new or changed rate is unlawful, it is authorized to require the pipeline to refund revenues collected in excess of the just and reasonable rate during the term of the investigation.

The rates charged by our natural gas pipelines may also be affected by the ongoing uncertainty regarding FERC's current income tax allowance policy. In July 2016, the United States Court of Appeals for the District of Columbia Circuit issued its opinion in *United Airlines, Inc., et al.v. FERC*, finding that FERC had acted arbitrarily and capriciously when it failed to demonstrate that permitting an interstate petroleum products pipeline organized as a limited partnership to include an income tax allowance in the cost of service underlying its rates in addition to the discounted cash flow return on equity would not result in the pipeline double-recovering its investors' income taxes. The court vacated FERC's order and remanded to FERC to consider mechanisms for demonstrating that there is no double recovery as a result of the income tax allowance. On December 15, 2016, FERC issued a Notice of Inquiry seeking comment on how to address any double recovery resulting from its income tax allowance policy. FERC is currently considering whether, and if so, to what extent, pipelines owned by pass-through entities such as MLPs may include income tax allowance in rates to compensate for the income tax liability of investors.

Interstate natural gas pipelines regulated by FERC are required to comply with numerous regulations related to standards of conduct, market transparency, and market manipulation. FERC's standards of conduct regulate the manner in which interstate natural gas pipelines may interact with their marketing affiliates. FERC's market oversight and transparency regulations require regulated entities to submit annual reports of threshold purchases or sales of natural gas and publicly post certain information on scheduled volumes. FERC's market manipulation regulations, promulgated pursuant to the Energy Policy Act of 2005 (the "EPAct 2005"), 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) make any untrue statement of material fact or omit to make any statement necessary to make the statements made not misleading; or (3) engage in any act or practice that operates as a fraud or deceit upon any person. The EPAct 2005 also amends the NGA and the Natural Gas Policy Act of 1978 (“NGPA”) to give FERC authority to impose civil penalties for violations of these statutes up to $1.0 million per day per violation for violations occurring after August 8, 2005. The maximum penalty authority established by the statute has been and will continue to be adjusted periodically for inflation. Should we fail to comply with all applicable FERC-administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines.

Our intrastate natural gas pipelines also transport gas in interstate commerce and, thus, the rates, terms and conditions of such services are subject to FERC jurisdiction under Section 311 of the NGPA (“Section 311”). Pipelines providing transportation service under Section 311 are required to provide services on an open and nondiscriminatory basis and the maximum rates for intrastate transportation services must be “fair and equitable.” Such rates are generally subject to review every five years by FERC or by an appropriate state agency.

Interstate Liquids Pipeline Regulation. We own certain liquids and crude oil pipelines that are regulated by FERC as common carrier interstate pipelines under the Interstate Commerce Act (“ICA”), the Energy Policy Act of 1992 and related rules and orders. These assets include our ORV, VEX, Chickadee and Cajun-Sibon NGL pipelines.

FERC regulation requires that interstate liquids pipeline rates and terms and conditions of service, including rates for transportation of crude oil, condensate and NGLs, be filed with FERC and that these rates and terms and conditions of service be “just and reasonable” and not unduly discriminatory or unduly preferential.

Rates of interstate liquids pipelines are currently regulated by FERC primarily through an annual indexing methodology, under which pipelines increase or decrease their rates in accordance with an index adjustment specified by FERC. This adjustment is subject to review every five years. For the five-year period beginning on July 1, 2016, FERC established an annual index adjustment equal to the change in the producer price index for finished goods plus 1.23%. On October 20, 2016, however, FERC issued an Advance Notice of Proposed Rulemaking indicating that FERC is considering a new policy that would deny proposed index increases for pipelines under certain circumstances where revenues exceed cost-of-service by a certain percentage or where the proposed index increases exceed certain annual cost changes reported to FERC. Under current FERC regulations, liquids pipelines can request a rate increase that exceeds the rate obtained through application of the indexing methodology by using a cost-of-service approach, but only after the pipeline establishes that a substantial divergence exists between the actual costs experienced by the pipeline and the rates resulting from application of the indexing methodology. The rates charged by our interstate liquids pipelines may also be affected by the ongoing uncertainty regarding FERC’s current income tax allowance policy discussed above.

The ICA permits interested persons to challenge proposed new or changed rates and authorizes FERC to suspend the effectiveness of such rates for up to seven months and investigate such rates. If, upon completion of an investigation, FERC finds that the new or changed rate is unlawful, it is authorized to require the pipeline to refund revenues collected in excess of the just and reasonable rate during the term of the investigation. FERC may also investigate, upon complaint or on its own motion, rates that are already in effect and may order a carrier to change its rates prospectively. Under certain circumstances, FERC could limit our ability to set rates based on our costs or could order us to reduce our rates and pay reparations to complaining shippers for up to two years prior to the date of the complaint. FERC also has the authority to change our terms and conditions of service if it determines that they are unjust and unreasonable or unduly discriminatory or preferential.

As we acquire, construct and operate new liquids assets and expand our liquids transportation business, the classification and regulation of our liquids transportation services are subject to ongoing assessment and change based on the services we provide and determinations by FERC and the courts. Such changes may subject additional services we provide to regulation by FERC.

Intrastate Natural Gas Pipeline Regulation. In addition to the Section 311 regulation discussed above, our intrastate natural gas pipeline operations are subject to regulation by various state agencies. Most state agencies possess the authority to review and authorize natural gas transportation transactions and the construction, acquisition, abandonment and interconnection of physical facilities. State agencies also may regulate transportation rates, service terms and conditions and contract pricing.

Intrastate Liquids Pipeline Regulation. Intrastate NGL and other petroleum pipelines are not generally subject to rate regulation by FERC, but they are subject to regulation by various agencies in the respective states where they are located. While such regulatory regimes vary, state agencies typically require intrastate NGL and petroleum pipelines to file their rates with the agencies and permit shippers to challenge existing rates or proposed rate increases.

Gathering Pipeline Regulation. Section 1(b) of the NGA exempts natural gas gathering facilities from the jurisdiction of FERC under the NGA. We own a number of natural gas pipelines that we believe meet the traditional tests FERC has used to establish that a pipeline is a gathering pipeline and therefore not subject to FERC jurisdiction. The distinction between FERC-regulated transmission services and federally unregulated gathering services is the subject of substantial, on-going litigation, however, so the classification and regulation of our gathering facilities are subject to change. State regulation of gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements and complaint-based rate regulation.

In addition, we are subject to some state ratable take and common purchaser statutes. 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.

Intrastate Natural Gas Storage Regulation. The storage field injection and withdrawal wells used in association with the Acacia system, along with water disposal wells located at the Bridgeport processing facility, are subject to the jurisdiction of the Railroad Commission of Texas (“TRRC”). TRRC regulations require that we report the volumes of natural gas and water disposal associated with the operations of such wells on a monthly and annual basis, respectively. Results of periodic mechanical integrity tests must also be reported to the TRRC. In addition, our underground gas storage caverns in Louisiana are subject to the jurisdiction of the Louisiana Department of Natural Resources (“LDNR”). In recent years, LDNR has put in place more comprehensive regulations governing underground hydrocarbon storage in salt caverns.

Sales of Natural Gas and NGLs. The prices at which we sell natural gas and NGLs currently are not subject to federal regulation and, for the most part, are not subject to state regulation. Our natural gas and NGL sales are affected by the availability, terms, cost and regulation of pipeline transportation.

Employee Safety. We are subject to the requirements of the Occupational Safety and Health Act (“OSHA”), and comparable state laws that regulate the protection of the health and safety of workers. In addition, the OSHA hazard communication standard requires that information be maintained about hazardous materials used or produced in operations and that this information be provided to employees, state and local government authorities and citizens. We believe that our operations are in substantial compliance with the OSHA requirements including general industry standards, record keeping requirements, and monitoring of occupational exposure to regulated substances.

Pipeline Safety Regulations. Our pipelines are subject to regulation by the DOT’s Pipeline and Hazardous Materials Safety Administration (“PHMSA”) pursuant to the Natural Gas Pipeline Safety Act of 1968 (“NGPSA”), and the Pipeline Safety Improvement Act of 2002 (“PSIA”). The NGPSA regulates safety requirements in the design, construction, operation and maintenance of gas pipeline facilities. The PSIA established mandatory inspections for all U.S. crude oil and natural gas transportation pipelines and some gathering lines in high-consequence areas (“HCAs”), which include, among other things, areas of high population density or that serve as sources of drinking water. PHMSA has developed regulations implementing the PSIA that require transportation pipeline operators to implement integrity management programs, including more frequent inspections and other measures to ensure pipeline safety in HCAs.

The Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011 increased penalties for safety violations, established additional safety requirements for newly constructed pipelines and required studies of certain safety issues that could result in the adoption of new regulatory requirements for existing pipelines. In April 2016, PHMSA published a notice of proposed rulemaking, or NPRM, addressing natural gas transmission and gathering lines. The proposed rule would, among other things, change existing integrity management requirements, expand assessment and repair requirements to pipelines in “moderate-consequence areas,” including areas of medium population density and increase requirements for monitoring and inspection of pipeline segments located outside of HCAs. Further, this NPRM would require that records or other data relied on to determine operating pressures must be traceable, verifiable and complete.

Locating such records and, in the absence of any such records, verifying maximum pressures through physical testing or modifying or replacing facilities, could significantly increase our costs. Additionally, failure to locate such records or verify maximum pressures could result in the reduction of allowable operating pressures, which would reduce available capacity on our pipelines.

In June 2016, the President of the United States signed the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2016 (the "PIPES Act"), which reauthorizes PHMSA's oil and gas pipeline programs through 2019. Pursuant to the PIPES Act, on December 14, 2016, PHMSA issued an interim final rule ("IFR") that addresses safety issues related to downhole facilities. The IFR incorporates by reference two of the American Petroleum Institute's Recommended Practice standards and mandates certain reporting requirements for operators of underground natural gas storage facilities. Along with other operators of natural gas storage facilities, we will have one year from January 18, 2017, the effective date of the IFR to implement this first set of PHMSA regulations governing underground storage fields.

In addition, on January 13, 2017, PHMSA finalized new hazardous liquid pipeline safety regulations extending certain regulatory reporting requirements to all hazardous liquid gathering (including oil) pipelines. The final rule requires additional event-driven and periodic inspections, requires the use of leak detection systems on all hazardous liquid pipelines, modifies repair criteria, and requires certain pipelines to eventually accommodate in-line inspection tools. The effective date of this final rule is currently uncertain due to a regulatory freeze implemented by the Trump administration on January 20, 2017.

On January 23, 2017, PHMSA published in the Federal Register amendments to the pipeline safety regulations to address requirements of the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 and to update and clarify certain regulatory requirements regarding notifications of accidents and incidents. The final rule also adds provisions for cost recovery for design reviews of certain new projects, renews existing special permits, and incorporates certain standards for in-line inspections and stress corrosion cracking assessments. The effective date of the final rule would have been March 24, 2017; however, the rule is subject to a regulatory freeze pending review by the Trump administration, unless exempted by PHMSA and OMB due to health and safety considerations.

At the state level, several states have passed legislation or promulgated rulemaking dealing with pipeline safety. We believe that our pipeline operations are in substantial compliance with applicable PHMSA and state requirements; however, due to the possibility of new or amended laws and regulations or reinterpretation of existing laws and regulations, there can be no assurance that future compliance with PHMSA or state requirements will not have a material adverse effect on our financial condition, results of operations or cash flows.

On November 2, 2015, PHMSA issued a Notice of Probable Violation and Proposed Compliance Order (the "NOPV") asserting that we have probable violations of 49 CFR Part 195 due to the misclassification of a transmission line as a gathering line. Transmission lines are subject to more fulsome pipeline safety regulations than gathering lines. The NOPV proposed a compliance order requiring us to satisfy the Part 195 requirements applicable to transmission lines but did not propose a penalty. We disagree with the assertion of PHMSA that the pipeline meets the definition of a transmission rather than gathering line. Accordingly, on December 30, 2015, we objected to the NOPV and requested a hearing. The hearing took place on July 27, 2016, and we are awaiting a decision from PHMSA regarding the arguments presented at the hearing. We cannot predict the outcome of our challenge. In the event the pipeline in question is ultimately treated as a transmission line rather than a gathering line, we estimate that we would incur costs of approximately $2.1 million over a two-year period to develop and implement a Part 195-compliant integrity management program, including hydrostatic testing and a leak detection and repair program.

Environmental Matters

General. Our operations involve processing and pipeline services for delivery of hydrocarbons (natural gas, NGLs, crude oil and condensates) from point-of-origin at oil and gas wellheads operated by our suppliers to our end-use market customers. Our facilities include natural gas processing and fractionation plants, natural gas and NGL storage caverns, brine disposal wells, pipelines and associated facilities, fractionation and storage units for NGLs, and transportation and delivery of hydrocarbons. As with all companies in our industrial sector, our operations are subject to stringent and complex federal, state and local laws and regulations relating to discharge of hazardous substances or solid wastes into the environment or otherwise relating to protection of the environment. Compliance with existing and anticipated environmental laws and regulations increases our overall costs of doing business, including costs of planning, constructing, and operating plants, pipelines, and other facilities, as well as capital expenditures necessary to maintain or upgrade equipment and facilities. Similar costs are likely upon changes in laws or regulations and upon any future acquisition of operating assets.

Any failure to comply with applicable environmental laws and regulations, including those relating to equipment failures, and obtaining required governmental approvals, may result in the assessment of administrative, civil or criminal penalties, imposition of investigatory or remedial activities and, in certain, less common circumstances, issuance of temporary or permanent injunctions or construction or operation bans or delays. As part of the regular evaluation of our operations, we routinely review and update governmental approvals as necessary.

The continuing trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment, and thus there can be no assurance as to the amount or timing of future expenditures for environmental compliance or remediation, and actual future expenditures may be different from the amounts we currently anticipate. Moreover, risks of process upsets, accidental releases or spills are associated with possible future operations, and we cannot assure you that we will not incur significant costs and liabilities, including those relating to claims for damage to property and persons as a result of any such upsets, releases or spills. We may be unable to pass on current or future environmental costs to our customers. A discharge or release of hydrocarbons, hazardous substances or solid wastes into the environment could, to the extent losses related to the event are not insured, subjects us to substantial expense, including both the cost to comply with applicable laws and regulations and to pay fines or penalties that may be assessed and the cost related to claims made by neighboring landowners and other third parties for personal injury or damage to natural resources or property. We attempt to anticipate future regulatory requirements that might be imposed and plan accordingly to comply with changing environmental laws and regulations and to minimize costs with respect to more stringent future laws and regulations or more rigorous enforcement of existing laws and regulations.

Hazardous Substances and Solid Waste. Environmental laws and regulations that relate to the release of hazardous substances or solid wastes into soils, sediments, groundwater and surface water and/or include measures to prevent and control pollution may pose the highest potential cost to our industrial sector. These laws and regulations generally regulate the generation, storage, treatment, transportation and disposal of solid wastes and hazardous substances and may require investigatory and corrective actions at facilities where such waste or substance may have been released or disposed. For instance, the Comprehensive Environmental Response, Compensation, and Liability Act (“CERCLA”), also known as the federal “Superfund” law, and comparable state laws impose liability without regard to fault or the legality of the original conduct on certain classes of persons that contributed to a release of a “hazardous substance” into the environment. Potentially responsible persons include the owner or operator of the site where a release occurred and companies that disposed or arranged for the disposal of the hazardous substances found at an off-site location, such as a landfill. Under CERCLA, these persons may be subject to joint and several liability for the costs of cleaning up and restoring sites where hazardous substances have been released into the environment and for damages to natural resources. CERCLA also authorizes the U.S. Environmental Protection Agency (“EPA”) and, in some cases, third parties to take actions in response to threats to public health or the environment and to seek recovery of costs they incur from the potentially 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 solid wastes released into the environment. Although petroleum, natural gas and NGLs are excluded from CERCLA’s definition of a “hazardous substance,” in the course of ordinary operations, we may generate wastes that may fall within the definition of a “hazardous substance.” In addition, there are other laws and regulations that can create liability for releases of petroleum, natural gas or NGLs. Moreover, we may be responsible under CERCLA or other laws for all or part of the costs required to clean up sites at which such substances have been disposed. We have not received any notification that we may be potentially responsible for cleanup costs under CERCLA or any analogous federal, state, or local law.

We also generate, and may in the future generate, both hazardous and nonhazardous solid wastes that are subject to requirements of the federal Resource Conservation and Recovery Act ("RCRA") and/or comparable state statutes. From time to time, the EPA and state regulatory agencies have considered the adoption of stricter disposal standards for nonhazardous wastes, including crude oil, condensate and natural gas wastes. Moreover, it is possible that some wastes generated by us that are currently exempted from the definition of hazardous waste may in the future lose this exemption and be designated as "hazardous wastes," resulting in the wastes being subject to more rigorous and costly management and disposal requirements. Additionally, the Toxic Substances Control Act ("TSCA") and analogous state laws impose requirements on the use, storage and disposal of various chemicals and chemical substances. Changes in applicable laws or regulations may result in an increase in our capital expenditures or plant operating expenses or otherwise impose limits or restrictions on our production and operations.

We currently own or lease, have in the past owned or leased, and in the future may own or lease, properties that have been used over the years for brine disposal operations, crude oil and condensate transportation, natural gas gathering, treating or processing and for NGL fractionation, transportation or storage. Solid waste disposal practices within the NGL industry and other oil and natural gas related industries have improved over the years with the passage and implementation of various environmental laws and regulations. Nevertheless, some hydrocarbons and other solid wastes may have been released on or under various properties owned, leased or operated by us during the operating history of those properties. In addition, a number of these properties may have been operated by third parties over whose operations and hydrocarbon and waste management practices we had no control. These properties and wastes disposed thereon may be subject to the Safe Drinking Water Act, CERCLA, RCRA, TSCA and analogous state laws. Under these laws, we could be required, alone or in participation with others, to remove or remediate previously disposed wastes or property contamination, if present, including groundwater contamination, or to take action to prevent future contamination.

Air Emissions. Our current and future operations are subject to the federal Clean Air Act and regulations promulgated thereunder and under comparable state laws and regulations. These laws and regulations regulate emissions of air pollutants from various industrial sources, including our facilities, and impose various control, monitoring, and reporting requirements. Pursuant to these laws and regulations, we may be required to obtain environmental agency pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions or result in an increase in existing air emissions, obtain and comply with the terms of air permits, which include various emission and operational limitations, or use specific emission control technologies to limit emissions. We likely will be required to incur certain capital expenditures in the future for air pollution control equipment in connection with maintaining or obtaining governmental approvals addressing air emission-related issues. Failure to comply with applicable air statutes or regulations may lead to the assessment of administrative, civil or criminal penalties and may result in the limitation or cessation of construction or operation of certain air emission sources or require us to incur additional capital expenditures. Although we can give no assurances, we believe such requirements will not have a material adverse effect on our financial condition, results of operations or cash flows, and the requirements are not expected to be more burdensome to us than to any similarly situated company.

In addition, the EPA included Wise County, the location of our Bridgeport facility, in its January 2012 revision to the Dallas-Ft. Worth ozone nonattainment area for the 2008 revised ozone national ambient air quality standard ("NAAQS"). As a result of this designation, new major sources in Wise County, meaning sources that emit greater than 100 tons/year of nitrogen oxides ("NOx") and volatile organic compounds ("VOCs"), as well as major modifications of existing facilities in the county resulting in net emissions increases of greater than 40 tons/year of NOx or VOCs, are subject to more stringent new source review ("NSR") pre-construction permitting requirements than they would be in an area that is in attainment with the 2008 ozone NAAQS. NSR pre-construction permits can take twelve to eighteen months to obtain and require the permit applicant to offset the proposed emission increases with reductions elsewhere at a 1.15 to 1 ratio. On October 26, 2016, the EPA finalized its 2015 revised ozone NAAQS that, if implemented, will further restrict ozone within the Dallas-Ft. Worth nonattainment area. The 2015 ozone NAAQS are being challenged in the U.S. Court of Appeals for the D.C. Circuit. The appeal remains pending.

Effective May 15, 2012, the EPA promulgated rules under the Clean Air Act that established new air emission controls for oil and natural gas production, pipelines and processing operations under the New Source Performance Standards ("NSPS") and National Emission Standards for Hazardous Air Pollutants ("NESHAPs") programs. These rules require the control of emissions through reduced emission (or "green") completions and establish specific new requirements regarding emissions from wet seal and reciprocating compressors, pneumatic controllers, and storage vessels at production facilities, gathering systems, boosting facilities, and onshore natural gas processing plants. In addition, the rules revised existing requirements for VOC emissions from equipment leaks at onshore natural gas processing plants by lowering the leak definition for valves from 10,000 parts per million to 500 parts per million and requiring the monitoring of connectors, pumps, pressure relief devices and open-ended lines. These rules required a number of modifications to our assets and operations. In October 2012, several challenges to the EPA's NSPS and NESHAPs rules for the industry were filed by various parties, including environmental groups and industry associations. In a January 16, 2013 unopposed motion to hold this litigation in abeyance, the EPA indicated that it may reconsider some aspects of the rules. The case remains in abeyance. The EPA has since revised certain aspects of the rules and has indicated that it may reconsider other aspects of the rules. Depending on the outcome of such proceedings, the rules may be further modified or rescinded or the EPA may issue new rules. We cannot predict the costs of compliance with any modified or newly issued rules.

In partial response to the issues raised regarding the 2012 rulemaking, the EPA recently finalized new rules that took effect August 2, 2016 to regulate emissions of methane and VOCs from new and modified sources in the oil and gas sector. The EPA also finalized a rule regarding alternative criteria for aggregating multiple small surface sites into a single source for air quality permitting purposes. This rule could cause small facilities, on an aggregate basis, to be deemed a major source, thereby triggering more stringent air permitting processes and requirements across the oil and gas industry. On November 10, 2016, the EPA issued a final Information Collection Request ("ICR") that requires numerous oil and gas companies to provide information regarding methane emissions from existing oil and gas facilities, a step used to provide a basis for future rulemaking. We have received numerous EPA ICR requests, and are meeting with the EPA to discuss simplifying the requests. The EPA has delayed our ICR response deadline until these issues are resolved. The Obama Administration also indicated that other federal agencies, including the Bureau of Land Management ("BLM"), the Pipeline and Hazardous Materials Safety Administration ("PHMSA"), and the Department of Energy would be imposing new or more stringent regulations on the oil and gas sector in order to further reduce methane emissions. For example, the BLM adopted new rules on November 15, 2016, to be effective on January 17, 2017, to reduce venting, flaring, and leaks during oil and natural gas production activities on onshore federal and Indian leases. As a result of this continued regulatory focus and other factors, additional GHG regulation of the oil and gas industry remains possible. Compliance with such rules could result in additional costs, including increased capital expenditures and operating costs for us and for other companies in our industry. While we are not able at this time to estimate such additional costs, as is the case with similarly situated entities in the industry, they could be significant for us. Compliance with such rules, as well as any new state rules, may also make it more difficult for our suppliers and customers to operate, thereby reducing the volume of natural gas transported through our pipelines, which may adversely affect our business. However, the status of recent and future rules and rulemaking initiatives under the new Trump Administration is uncertain.

Climate Change. In December 2009, the EPA determined that emissions of certain gases, commonly referred to as "greenhouse gases," present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to the warming of the earth's atmosphere and other climatic changes. Based on these findings, the EPA adopted regulations under existing provisions of the federal Clean Air Act, that require Prevention of Significant Deterioration ("PSD") pre construction permits, and Title V operating permits for greenhouse gas emissions from certain large stationary sources. Under these regulations, facilities required to obtain PSD permits must meet "best available control technology" standards for their greenhouse gas emissions established by the states or, in some cases, by the EPA on a case by case basis. The EPA has also adopted rules requiring the monitoring and reporting of greenhouse gas emissions from specified sources in the United States, including, among others, certain onshore oil and natural gas processing and fractionating facilities. In addition, 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. Because regulation of greenhouse gas emissions is relatively new, further regulatory, legislative and judicial developments are likely to occur. Such developments in greenhouse gas initiatives may affect us and other companies operating in the oil and gas industry. In addition to these developments, recent judicial decisions have allowed certain tort claims alleging property damage to proceed against greenhouse gas emissions sources, which may increase our litigation risk for such claims. In addition, 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 entered into force November 4, 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. The status of the United States' commitment to Paris Agreement under the Trump Administration remains to be determined. Due to the uncertainties surrounding the regulation of and other risks associated with greenhouse gas emissions, we cannot predict the financial impact of related developments on us.

Federal or state legislative or regulatory initiatives that regulate or restrict emissions of greenhouse gases in areas in which we conduct business could adversely affect the availability of, or demand for, the products we store, transport and process, and, depending on the particular program adopted, could increase the costs of our operations, including costs to operate and maintain our facilities, install new emission controls on our facilities, acquire allowances to authorize our greenhouse gas emissions, pay any taxes related to our greenhouse gas emissions and/or administer and manage a greenhouse gas emissions program. We may be unable to recover any such lost revenues or increased costs in the rates we charge our customers, and any such recovery may depend on events beyond our control, including the outcome of future rate proceedings before FERC or state regulatory agencies and the provisions of any final legislation or regulations. Reductions in our revenues or increases in our expenses as a result of climate control initiatives could have adverse effects on our business our financial condition, results of operations or cash flows.

Due to their location, our operations along the Gulf Coast are vulnerable to operational and structural damages resulting from hurricanes and other severe weather systems, while inland operations include areas subject to tornadoes. Our insurance may not cover all associated losses. We are taking steps to mitigate physical risks from storms, but no assurance can be given that future storms will not have a material adverse effect on our business.

Hydraulic Fracturing and Wastewater. The Federal Water Pollution Control Act, also known as the Clean Water Act, and comparable state laws impose restrictions and strict controls regarding the discharge of pollutants, including NGL-related wastes, into state waters or waters of the United States. In June 2015, the EPA and the U.S. Army Corps of Engineers finalized a rule intended to clarify the meaning of the term "waters of the United States," which establishes the scope of regulated waters under the Clean Water Act. The rule has been challenged and was stayed by federal courts. Absent Congressional action, the rule will become applicable if the courts do not continue the stay of the rule during the litigation; if upheld, the rule is expected to expand federal jurisdiction under the Clean Water Act. Regulations promulgated pursuant to the Clean Water Act require that entities that discharge into federal and state waters obtain National Pollutant Discharge Elimination System ("NPDES") permits and/or state permits authorizing these discharges. The Clean Water Act and analogous state laws assess administrative, civil and criminal penalties for discharges of unauthorized pollutants into the water and impose substantial liability for the costs of removing spills from such waters. In addition, the Clean Water Act and analogous state laws require that individual permits or coverage under general permits be obtained by covered facilities for discharges of storm water runoff. We believe that we are in substantial compliance with Clean Water Act permitting requirements as well as the conditions imposed by our permits and that continued compliance with such existing permit conditions will not have a material effect on our financial condition, results of operations or cash flows.

We operate brine disposal wells that are regulated as Class II wells under the federal Safe Drinking Water Act ("SDWA"). The SDWA imposes requirements on owners and operators of Class II wells through the EPA's Underground Injection Control program, including construction, operating, monitoring and testing, reporting and closure requirements. Our brine disposal wells are also subject to comparable state laws and regulations, which in some cases are more stringent than requirements under the federal SDWA, such as the Ohio Department of Natural Resources rules that took effect October 1, 2012. These rules set new, more stringent standards for the permitting and operating of brine disposal wells, including extensive review of geologic data and use of state-of-the-art technology. The Ohio Department of Natural Resources also imposes requirements on the transportation and disposal of brine. Compliance with current and future laws and regulations regarding our brine disposal wells may impose substantial costs and restrictions on our brine disposal operations, as well as adversely affect demand for our brine disposal services. State and federal regulatory agencies recently have focused on a possible connection between the operation of injection wells used for oil and gas waste waters and an observed increase in minor seismic activity and tremors. When caused by human activity, such events are called induced seismicity. In a few instances, operators of injection wells in the vicinity of minor seismic events have reduced injection volumes or suspended operations, often voluntarily. A 2012 report published by the National Academy of Sciences concluded that only a very small fraction of the tens of thousands of injection wells have been suspected to be, or have been, the likely cause of induced seismicity. However, some state regulatory agencies have modified their regulations to account for induced seismicity. For example, TRRC rules allow the TRRC to modify, suspend, or terminate a permit based on a determination that the permitted activity is likely to be contributing to seismic activity. In the state of Ohio, the Ohio Department of Natural Resources ("ODNR") requires a seismic study prior to the authorization of any new disposal well. In addition, the ODNR has instituted a continuous monitoring network of seismographs and is able to curtail injected volumes regionally based upon seismic activity detected. The Oklahoma Corporation Commission has also taken steps to focus on induced seismicity, including increasing the frequency of required recordkeeping for wells that dispose into certain formations and considering seismic information in permitting decisions. For instance, on August 3, 2015, the OCC adopted a plan calling for mandatory reductions in oil and gas wastewater disposal well volumes, the implementation of which has involved reductions of injection or shut-ins of disposal wells. Regulatory agencies are continuing to study possible linkage between injection activity and induced seismicity. To the extent these studies result in additional regulation of injection wells, such regulations could impose additional regulations, costs and restrictions on our brine disposal operations.

It is common for our customers or suppliers to recover natural gas from deep shale formations through the use of hydraulic fracturing, combined with sophisticated horizontal drilling. Hydraulic fracturing is an important and commonly used process in the completion of wells by oil and gas producers. Hydraulic fracturing involves the injection of water, sand and chemical additives under pressure into rock formations to stimulate gas production. Due to public concerns raised regarding potential impacts of hydraulic fracturing on groundwater quality, legislative and regulatory efforts at the federal level and in some states and localities have been initiated to require or make more stringent the permitting and other regulatory requirements for hydraulic fracturing operations of our customers and suppliers. There are certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices, and a committee of the United States House of Representatives has conducted an investigation of hydraulic fracturing practices. On December 13, 2016, the EPA released a study of the potential adverse effects that hydraulic fracturing may have on water quality and public health, concluding that there is scientific evidence that hydraulic fracturing activities potentially can impact drinking water resources in the United States under some circumstances. This study or similar studies could spur initiatives to further regulate hydraulic fracturing. In June 2016, the EPA finalized rules prohibiting discharges of wastewater from hydraulic fracturing operations to publicly owned wastewater treatment plants. The EPA has also issued an advance notice of proposed rulemaking under the Toxic Substances Control Act to gather information regarding the potential regulation of chemical substances and mixtures used in oil and gas exploration and production. Also, effective June 24, 2015, BLM adopted rules regarding well stimulation, chemical disclosures, water management, and other requirements for hydraulic fracturing on federal and Indian lands; however, a federal district court invalidated these BLM rules in June 2016 and an appeal is pending. Additional regulatory burdens in the future, whether federal, state or local, could increase the cost of or restrict the ability of our customers or suppliers to perform hydraulic fracturing. As a result, any increased federal, state or local regulation could reduce the volumes of natural gas that our customers move through our gathering systems which would materially adversely affect our financial condition, results of operations or cash flows.

Endangered Species and Migratory Birds. The Endangered Species Act ("ESA"), Migratory Bird Treaty Act ("MBTA"), and similar state and local laws restrict activities that may affect endangered or threatened species or their habitats or migratory birds. Some of our pipelines may be located in areas that are designated as habitats for endangered or threatened species, potentially exposing us to liability for impacts on an individual member of a species or to habitat. The Endangered Species Act can also make it more difficult to secure a federal permit for a new pipeline.

Office Facilities

We occupy approximately 108,500 square feet of space at our executive offices in Dallas, Texas under a lease expiring in August 2019. In November 2014, we entered into a new agreement to lease approximately 157,600 square feet of space for our executive offices in Dallas, Texas with a lease term commencing in August 2016 and expiring in February 2030.

Employees

As of December 31, 2016, we (through our subsidiaries) employed approximately 1,472 full-time employees. Approximately 336 of our employees were general and administrative, engineering, accounting and commercial personnel and the remainder were operational employees. We are not party to any collective bargaining agreements and we have not had any significant labor disputes in the past. We believe that we have good relations with our employees.

Item 1A. Risk Factors

The following risk factors and all other information contained in this report should be considered carefully when evaluating us. These risk factors could affect our actual results. Other risks and uncertainties, in addition to those that are described below, may also impair our business operations. If any of the following risks occur, our business, financial condition, results of operations or cash flows (including our ability to make distributions to our noteholders) could be *affected materially and adversely. In that case, we may be unable to make distributions to our unitholders and the trading price of our common units could decline. These risk factors should be read in conjunction with the other detailed information concerning us set forth in our accompanying financial statements and notes and contained in* "*Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations*" *included herein.*

We are dependent on Devon for a substantial portion of the natural gas that we gather, process and transport. The expiration of five-year MVCs from Devon at the end of 2018 and in April 2020, could result in a material decline in our operating results and cash available for distribution because the volumes of natural gas that we gathered, processed and transported for Devon during 2016 have been below the MVC levels under certain of our contracts.

We are dependent on Devon for a substantial portion of our natural gas supply. For the year ended December 31, 2016, Devon represented approximately 50% of our gross operating margin. In order to minimize volumetric exposure, in March 2014, we obtained five-year MVCs from Devon at the Bridgeport processing facility, Bridgeport and East Johnson County gathering systems and the central Oklahoma gathering system which expire on January 1, 2019. We also have a five-year, MVC from Devon attributable to the VEX pipeline which expires on April 1, 2020. If the volumes of natural gas and crude oil that we gather and transport on our systems are below the MVC levels after the contracts expire, we could experience a material decline in our combined total operating revenues and cash flow. For the years ended December 31, 2016, we recognized $26.4 million, $10.8 million, and $9.0 million under MVCs from Devon attributable to our Texas, Oklahoma and Crude and Condensate segments, respectively, because volumes have been below the minimum level. For the years ended December 31, 2015, we recognized $3.8 million, $20.1 million, and $0.5 million under MVCs from Devon attributable to our Texas, Oklahoma and Crude and Condensate segments, respectively.

Because we are substantially dependent on Devon as our primary customer and through its indirect control of our general partner, any development that materially and adversely affects Devon's operations, financial condition or market reputation could have a material and adverse impact on us. Material adverse changes at Devon could restrict our access to capital, make it more expensive to access the capital markets or increase the costs of our borrowings.

We are substantially dependent on Devon as our primary customer and through its indirect control of our general partner, and we expect to derive a majority of our gross operating margin from Devon for the foreseeable future. As a result, any event, whether in our area of operations or otherwise, that adversely affects Devon's production, financial condition, leverage, market reputation, liquidity, results of operations or cash flows may adversely affect our revenues and cash available for distribution. Accordingly, we are indirectly subject to the business risks of Devon, some of which are the following:

- potential changes in the supply of and demand for oil, natural gas and NGLs and related products and services;
- risks relating to Devon's exploration and drilling programs, including potential environmental liabilities;
- adverse effects of governmental and environmental regulation; and
- general economic and financial market conditions.

Further, we are subject to the risk of non-payment or non-performance by Devon, including with respect to our gathering and processing agreements. We cannot predict the extent to which Devon's business will be impacted by pricing conditions in the energy industry, nor can we estimate the impact such conditions would have on Devon's ability to perform under our gathering and processing agreements. Additionally, due to our relationship with Devon, our ability to access the capital markets, or the pricing or other terms of any capital markets transactions, may be adversely affected by any impairments to Devon's financial condition or adverse changes in its credit ratings. In February 2016, S&P Global Ratings ("S&P") and Moody's Investors Services ("Moody's") each downgraded Devon to a BBB and Ba2 credit rating, respectively. Any material limitations on our ability to access capital as a result of such adverse changes at Devon could limit our ability to obtain future financing under favorable terms, or at all, or could result in increased financing costs in the future. Similarly, material adverse changes at Devon could negatively impact our unit price, limiting our ability to raise capital through equity issuances or debt financing or our ability to engage in, expand or pursue our business activities and could also prevent us from engaging in certain transactions that might otherwise be considered beneficial to us.

Please see "Item 1A. Risk Factors" in Devon's Annual Report on Form 10-K for the year ended December 31, 2016 for a full discussion of the risks associated with Devon's business.

Adverse developments in our gathering, transmission, processing, crude oil, condensate, natural gas and NGL services businesses would reduce our ability to make distributions to our unitholders.

We rely exclusively on the revenues generated from our gathering, transmission, processing, fractionation, crude oil, natural gas, condensate and NGL services businesses and as a result our financial condition depends upon prices of, and continued demand for, natural gas, NGLs, crude oil and condensate. An adverse development in one of these businesses may have a significant impact on our financial condition and our ability to make distributions to our unitholders.

A significant portion of our operations are located in the Barnett Shale, making us vulnerable to risks associated with having revenue-producing operations concentrated in a limited number of geographic areas.

Our revenue-producing operations are geographically concentrated in the Barnett Shale, causing us to be disproportionally exposed to risks associated with regional factors. Specifically, our operations in the Barnett Shale accounted for approximately 17.5% of our consolidated revenues and approximately 40.2% of our consolidated gross operating margin for the year ended December 31, 2016. The concentration of our operations in this region also increases exposure to unexpected events that may occur in this region such as natural disasters or labor difficulties. Any one of these events has the potential to have a relatively significant impact on our operations and growth plans, decrease cash flows, increase operating and capital costs and prevent development within originally anticipated time frames. Any of these risks could have a material adverse effect on our financial condition, results of operations or cash flows.

We must continually compete for crude oil, condensate, natural gas and NGL supplies, and any decrease in supplies of such commodities could adversely affect our financial condition, results of operations or cash flows.

In order to maintain or increase throughput levels in our gathering systems and asset utilization rates at our processing plants and fractionators, we must continually contract for new product supplies. We may not be able to obtain additional contracts for crude oil, condensate, natural gas and NGL supplies. The primary factors affecting our ability to connect new wells to our gathering facilities include our success in contracting for existing supplies that are not committed to other systems and the level of drilling activity near our gathering systems. If we are unable to maintain or increase the volumes on our systems by accessing new supplies to offset the natural decline in reserves, our business and financial results could be materially, adversely affected. In addition, our future growth will depend in part upon whether we can contract for additional supplies at a greater rate than the rate of natural decline in our current supplies.

Fluctuations in energy prices can greatly affect production rates and investments by third parties in the development of new crude oil, condensate and natural gas reserves. During 2015 and 2016, we saw suppressed drilling activity due to low commodity prices. Although drilling activity has improved during 2016 in some of the most economic basins, including the STACK, SCOOP and CNOW basins in Oklahoma and the Permian basin in Texas, we could see downward pressure on future drilling activity in these basins if commodity prices decline below current levels, which may result in lower volumes. Tax policy changes or additional regulatory restrictions on development could also have a negative impact on drilling activity, reducing supplies of product available to our systems and assets. Additional governmental regulation of, or delays in issuance of permits for, the offshore exploration and production industry may negatively impact current and future volumes from offshore pipelines supplying our processing plants. We have no control over producers and depend on them to maintain sufficient levels of drilling activity. A continued decrease in the level of drilling activity or a material decrease in production in our principal geographic areas for a prolonged period, as a result of continued commodity prices or otherwise, likely would have a material adverse effect on our financial condition, results of operations and cash flows.

Any decrease in the volumes that we gather, process, fractionate or transport would adversely affect our financial condition, results of operations or cash flows.

Our financial performance depends to a large extent on the volumes of natural gas, crude oil, condensate and NGLs gathered, processed, fractionated and transported on our assets. Decreases in the volumes of natural gas, crude oil, condensate and NGLs we gather, process, fractionate or transport would directly and adversely affect our financial condition. These volumes can be influenced by factors beyond our control, including:

- environmental or other governmental regulations;
- weather conditions;
- increases in storage levels of natural gas, NGLs, crude oil and condensate;

- increased use of alternative energy sources;
- decreased demand for natural gas, NGLs, crude oil and condensate;
- continued fluctuations in commodity prices, including the prices of natural gas, NGLs, crude oil and condensate;
- economic conditions;
- supply disruptions;
- availability of supply connected to our systems; and
- availability and adequacy of infrastructure to gather and process supply into and out of our systems.

The volumes of natural gas, crude oil, condensate and NGLs gathered, processed, fractionated and transported on our assets also depend on the production from the regions that supply our systems. Supply of natural gas, crude oil, condensate and NGLs can be affected by many of the factors listed above, including commodity prices and weather. In order to maintain or increase throughput levels on our systems, we must obtain new sources of natural gas, crude oil, condensate and NGLs. The primary factors affecting our ability to obtain non-dedicated sources of natural gas, crude oil, condensate and NGLs include (i) the level of successful leasing, permitting and drilling activity in our areas of operation, (ii) our ability to compete for volumes from new wells and (iii) our ability to compete successfully for volumes from sources connected to other pipelines. We have no control over the level of drilling activity in our areas of operation, the amount of reserves associated with wells connected to our systems or the rate at which production from a well declines. In addition, we have no control over producers or their drilling or production decisions, which are affected by, among other things, the availability and cost of capital, levels of reserves, availability of drilling rigs and other costs of production and equipment.

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

GAAP requires us to test goodwill and intangible assets with indefinite useful lives for impairment on an annual basis or when events or circumstances occur indicating that goodwill might be impaired. Long-lived assets, including intangible assets with finite useful lives, are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. For the investments we account for under the equity method, the impairment test considers whether the fair value of the unconsolidated affiliate investment as a whole, not the underlying net assets, has declined and whether that decline is other than temporary. If we determine that an impairment is indicated, we would be required to 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. For the year ended December 31, 2015, we recognized a $12.1 million impairment on property, plant and equipment, primarily related to costs associated with the cancellation of various capital projects in our Texas, Louisiana, and Crude and Condensate segments. In addition, for the year ended December 31, 2015, we recognized a $223.1 million impairment of intangible assets in our Crude and Condensate segment and a goodwill impairment totaling $1,328.2 million in our Texas, Louisiana and Crude and Condensate segments. During February 2016, we determined that continued further weakness in the overall energy sector, driven by low commodity prices together with a further decline in our unit price subsequent to year-end, caused a change in circumstances warranting an interim impairment test. Based on these triggering events, we performed a goodwill impairment analysis in the first quarter of 2016 on all reporting units. Based on this analysis, a goodwill impairment loss for our Texas and Crude and Condensate reporting units in the amount of $566.3 million was recognized in the first quarter of 2016 and is included as an impairment loss in the consolidated statement of operations for the year ended December 31, 2016. Additional impairment of the value of our existing goodwill and intangible assets could have a significant negative impact on our future operating results.

Our construction of new assets may be more expensive than anticipated and may not result in revenue increases and may be subject to regulatory, environmental, political, legal and economic risks that could adversely affect our financial condition, results of operations or cash flows.

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 beyond our control including potential protests or legal actions by interested third parties, and may require the expenditure of significant amounts of capital. Financing may not be available on economically acceptable terms or at all. If we undertake these projects, we may not be able to complete them on schedule, at the budgeted cost or at all. Moreover, our revenues may not increase due to the successful construction of a particular project. For instance, if we expand a 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 promptly following completion of a project or at all. Moreover, we may construct facilities to capture anticipated future production growth in a region in which such growth does not materialize. As a result, new facilities may not be able to attract enough throughput to achieve our expected investment return, which could adversely affect our financial condition, results of operations or cash flows. In addition, the construction of additions to our existing gathering and processing assets will generally require us to obtain new rights-of-way and permits prior to constructing new pipelines or facilities. We may be unable to timely obtain such rights-of-way or permits to connect new product supplies to our existing gathering lines or capitalize on other attractive expansion opportunities. Additionally, it may become more expensive for us to obtain new rights-of-way or to expand or renew existing rights-of-way. If the cost of renewing or obtaining new rights-of-way increases, our cash flows could be adversely affected.

Construction of our major development projects subjects us to risks of construction delays, cost over-runs, limitations on our growth and negative effects on our financial condition, results of operations or cash flows.

We are engaged in the planning and construction of several major development projects, some of which will take a number of months before commercial operation. These projects are complex and subject to a number of factors beyond our control, including delays from third-party landowners, the permitting process, complying with laws, unavailability of materials, labor disruptions, environmental hazards, financing, accidents, weather and other factors. Any delay in the completion of these projects could have a material adverse effect on our financial condition, results of operations or cash flows. The construction of pipelines and gathering and processing and fractionation facilities requires the expenditure of significant amounts of capital, which may exceed our estimated costs. Estimating the timing and expenditures related to these development projects is very complex and subject to variables that can significantly increase expected costs. Should the actual costs of these projects exceed our estimates, our liquidity and capital position could be adversely affected. This level of development activity requires significant effort from our management and technical personnel and places additional requirements on our financial resources. We may not have the ability to attract and/or retain the necessary number of personnel with the skills required to bring complicated projects to successful conclusions.

We conduct a portion of our operations through joint ventures, which subjects us to additional risks that could have a material adverse effect on the success of these operations, our financial position, results of operations or cash flows.

We participate in several joint ventures, and we may enter into other joint venture arrangements in the future. The nature of a joint venture requires us to share control with unaffiliated third parties. If our joint venture partners do not fulfill their contractual and other obligations, the affected joint venture may be unable to operate according to its business plan, and we may be required to increase our level of commitment. If we do not timely meet our financial commitments or otherwise comply with our joint venture agreements, our ownership of and rights with respect to the applicable joint venture may be reduced or otherwise adversely affected. Differences in views among joint venture participants could also result in delays in business decisions or otherwise, failures to agree on major issues, operational inefficiencies and impasses, litigation or other issues. Third parties may also seek to hold us liable for the joint ventures' liabilities. These issues or any other difficulties that cause a joint venture to deviate from its original business plan could have a material adverse effect on our financial condition, results of operations or cash flows.

Any reductions in our credit ratings could increase our financing costs, the cost of maintaining certain contractual relationships and reduce our cash available for distribution.

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 so warrant. In February 2016, S&P and Moody's downgraded us to a BBB- and Ba2 credit rating, respectively. Any future downgrade could increase the cost of borrowings under our credit facility. Any downgrade could also lead to higher borrowing costs and, if below investment grade, could require:

- additional or more restrictive covenants that impose operating and financial restrictions on us and our subsidiaries;
- our subsidiaries to guarantee such debt and certain existing debt, including our senior notes;
- us and our subsidiaries to provide collateral to secure such debt; and

- us or our subsidiaries to post cash collateral or letters of credit under our hedging arrangements or in order to purchase commodities or obtain trade credit.

Any increase in our financing costs or additional or more restrictive covenants resulting from a credit rating downgrade could adversely affect our ability to finance future operations and make cash distributions to unitholders. If a credit rating downgrade and the resultant collateral requirement were to occur at a time when we were experiencing significant working capital requirements or otherwise lacked liquidity, our results of operations and our ability to make cash distributions to unitholders could be adversely affected.

We typically do not obtain independent evaluations of hydrocarbon reserves; therefore, volumes we service in the future could be less than we anticipate.

We typically do not obtain, on a regular basis, independent evaluations of hydrocarbon reserves connected to our gathering systems or that we otherwise service due to the unwillingness of producers to provide reserve information as well as the cost of such evaluations. Accordingly, we do not have independent estimates of total reserves serviced by our assets or the anticipated life of such reserves. If the total reserves or estimated life of the reserves is less than we anticipate and we are unable to secure additional sources, then the volumes transported on our gathering systems or that we otherwise service in the future could be less than anticipated. A decline in the volumes could have a material adverse effect on our financial condition, results of operations or cash flows.

We may not be successful in balancing our purchases and sales.

We are a party to certain long-term gas, NGL and condensate sales commitments that we satisfy through supplies purchased under long-term gas, NGL and condensate purchase agreements. When we enter into those arrangements, our sales obligations generally match our purchase obligations. However, over time the supplies that we have under contract may decline due to reduced drilling or other causes and we may be required to satisfy the sales obligations by purchasing additional gas at prices that may exceed the prices received under the sales commitments. In addition, a producer could fail to deliver contracted volumes or deliver in excess of contracted volumes, or a consumer could purchase more or less than contracted volumes. Any of these actions could cause our purchases and sales not to be balanced. If our purchases and sales are not balanced, we will face increased exposure to commodity price risks and could have increased volatility in our operating income.

We have made commitments to purchase natural gas in production areas based on production-area indices and to sell the natural gas into market areas based on market-area indices, pay the costs to transport the natural gas between the two points and capture the difference between the indices as margin. Changes in the index prices relative to each other (also referred to as basis spread) can significantly affect our margins or even result in losses. For example, we are a party to one contract associated with our north Texas operations with a term to 2019 to supply approximately 150,000 MMBtu/d of gas. We buy gas for this contract on several different production-area indices and sell the gas into a different market area index. We realize a loss on the delivery of gas under this contract each month based on current prices. The balance sheet as of December 31, 2016 reflects a liability of $44.8 million related to this performance obligation based on forecasted discounted cash obligations in excess of market under this gas delivery contract. Reduced supplies and narrower basis spreads in recent periods have increased the losses on this contract, and greater losses on this contract could occur in future periods if these conditions persist or become worse.

Our profitability is dependent upon prices and market demand for crude oil, condensate, natural gas and NGLs that are beyond our control and have been volatile. The current depressed commodity price environment, if it continues, could result in financial losses and reduce our cash available for distribution.

We are subject to significant risks due to fluctuations in commodity prices. We are directly exposed to these risks primarily in the gas processing and NGL fractionation components of our business. For the year ended December 31, 2016, approximately 3.0% of our total gross operating margin was generated under percent of liquids contracts and percent of proceeds contracts, with most of these contracts relating to our Permian processing plants. Under percent of liquids contracts we receive a fee in the form of a percentage of the liquids recovered and the producer bears all the cost of the natural gas shrink. Accordingly, our revenues under percent of liquids contracts are directly impacted by the market price of NGLs. Gross operating margin results under percent of proceeds contracts are impacted only by the value of the natural gas or liquids produced with margins higher during periods of higher natural gas and liquids prices.

We also realize processing gross operating margins under processing margin contracts. For the year ended December 31, 2016, approximately 0.9% of our total gross operating margin was generated under processing margin contracts. We have a number of processing margin contracts for activities at our Plaquemine and Pelican processing plants. Under this type of contract, we pay the producer for the full amount of inlet gas to the plant, and we make a margin based on the difference between the value of liquids recovered from the processed natural gas as compared to the value of the natural gas volumes lost ("shrink") and the cost of fuel used in processing. The shrink and fuel losses are referred to as plant thermal reduction ("PTR"). Our margins from these contracts can be greatly reduced or eliminated during periods of high natural gas prices relative to liquids prices.

We are also indirectly exposed to commodity prices due to the negative impacts on production and the development of production of crude oil, condensate, natural gas and NGLs connected to or near our assets and on our margins for transportation between certain market centers. Low prices for these products have reduced the demand for our services and volumes on our systems, and continued low prices may reduce such demand even further.

Although the majority of our NGL fractionation business is under fee-based arrangements, a portion of our business is exposed to commodity price risk because we realize a margin due to product upgrades associated with our Cajun-Sibon fractionation business. For the year ended December 31, 2016, margins realized associated with product upgrades represented less than 1% of our gross operating margin.

The prices of crude oil, condensate, natural gas and NGLs were extremely volatile during 2016. Crude oil, weighted average NGL, and natural gas prices increased 46%, 53% and 60%, respectively, from January 1, 2016 to December 31, 2016. We expect this volatility to continue. For example, crude oil prices (based on the NYMEX futures daily close prices for the prompt month) in 2016 ranged from a high of $54.06 per Bbl in December 2016 to a low of $26.21 per Bbl in February 2016. Weighted average NGL prices in 2016 (based on the Oil Price Information Service ("OPIS") Napoleonville daily average spot liquids prices) ranged from a high of $0.66 per gallon in December 2016 to a low of $0.31 per gallon in January 2016. Natural gas prices (based on Gas Daily Henry Hub closing prices) during 2016 ranged from a high of $3.93 per MMBtu in December 2016 to a low of $1.64 per MMBtu in March 2016.

The markets and prices for crude oil, condensate, natural gas and NGLs depend upon factors beyond our control that make it difficult to predict future commodity price movements with any certainty. These factors include the supply and demand for crude oil, condensate, natural gas and NGLs, which fluctuate with changes in market and economic conditions and other factors, including:

- the impact of weather on the demand for crude oil and natural gas;
- the level of domestic crude oil, condensate and natural gas production;
- technology, including improved production techniques (particularly with respect to shale development);
- the level of domestic industrial and manufacturing activity;
- the availability of imported crude oil, natural gas and NGLs;
- international demand for crude oil and NGLs;
- actions taken by foreign crude oil and gas producing nations;
- the continued threat of terrorism and the impact of military action and civil unrest;
- the availability of local, intrastate and interstate transportation systems;
- the availability of downstream NGL fractionation facilities;
- the availability and marketing of competitive fuels;
- the impact of energy conservation efforts; and
- the extent of governmental regulation and taxation, including the regulation of hydraulic fracturing and "greenhouse gases."

Changes in commodity prices also indirectly impact our profitability by influencing drilling activity and well operations, and thus the volume of gas, crude oil and condensate we gather and process and NGLs we fractionate. The volatility in commodity prices may cause our gross operating margin and cash flows to vary widely from period to period. Our hedging strategies may not be sufficient to offset price volatility risk and, in any event, do not cover all of our throughput volumes. Moreover, hedges are subject to inherent risks, which we describe in "Item 7A. Quantitative and Qualitative Disclosure about Market Risk." Our use of derivative financial instruments does not eliminate our exposure to fluctuations in commodity prices and interest rates and has in the past and could in the future result in financial losses or reduce our income.

If third-party pipelines or other midstream facilities interconnected to our gathering or transportation systems become partially or fully unavailable, or if the volumes we gather, process or transport do not meet the quality requirements of the pipelines or facilities to which we connect, our gross operating margin and cash flow could be adversely affected.

Our gathering, processing and transportation assets connect to other pipelines or facilities owned and operated by unaffiliated third parties. The continuing operation of, and our continuing access to, such third-party pipelines, processing facilities and other midstream facilities is not within our control. These pipelines, plants and other midstream facilities may become unavailable because of testing, turnarounds, line repair, maintenance, reduced operating pressure, lack of operating capacity, regulatory requirements and curtailments of receipt or deliveries due to insufficient capacity or because of damage from severe weather conditions or other operational issues. In addition, if our costs to access and transport on these third-party pipelines significantly increase, our profitability could be reduced. If any such increase in costs occurs, if any of these pipelines or other midstream facilities become unable to receive, transport or process product, or if the volumes we gather or transport do not meet the product quality requirements of such pipelines or facilities, our operating margin and cash flow could be adversely affected.

Our debt levels could limit our flexibility and adversely affect our financial health or limit our flexibility to obtain financing and to pursue other business opportunities.

We continue to have the ability to incur debt, subject to limitations in our credit facility. Our level of indebtedness could have important consequences to us, including the following:

- our ability to obtain additional financing, if necessary, for working capital, capital expenditures, acquisitions or other purposes may be impaired or such financing may not be available on favorable terms;
- our funds available for operations, future business opportunities and distributions to unitholders will be reduced by that portion of our cash flows required to make interest payments on our debt;
- our debt level will make us more vulnerable to general adverse economic and industry conditions;
- limit our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate; and
- increase the risk that we may default on our debt obligations.

In addition, our ability to make scheduled payments or to refinance our obligations depends on our successful financial and operating performance, which will be affected by prevailing economic, financial and industry conditions, many of which are beyond our control. If our cash flow and capital resources are insufficient to fund our debt service obligations, we may be forced to take actions such as reducing distributions, reducing or delaying our business activities, acquisitions, investments or capital expenditures, selling assets, restructuring or refinancing our debt or seeking additional equity capital. We may not be able to effect any of these actions on satisfactory terms or at all.

The terms of our credit facility and indentures may restrict our current and future operations, particularly our ability to respond to changes in business or to take certain actions.

Our credit agreement and the indentures governing our senior notes contain, and any future indebtedness we incur will likely contain, a number of restrictive covenants that impose significant operating and financial restrictions, including restrictions on our ability to engage in acts that may be in our best long-term interest. One or more of these agreements include covenants that, among other things, restrict our ability to:

- incur subsidiary indebtedness;
- engage in transactions with our affiliates;
- consolidate, merge or sell substantially all of our assets;
- incur liens;
- enter into sale and lease back transactions; and

- change business activities we conduct.

In addition, our credit facility requires us to satisfy and maintain a specified financial ratio. Our ability to meet that financial ratio can be affected by events beyond our control, and we cannot assure you that we will continue to meet that ratio.

Our ability to comply with the covenants and restrictions contained in our credit facility and indentures 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. A breach of any of these covenants could result in an event of default under our credit facility and indentures. Upon the occurrence of such an event of default, all amounts outstanding under the applicable debt agreements could be declared to be immediately due and payable and all applicable commitments to extend further credit could be terminated. If indebtedness under our credit facility or indentures is accelerated, there can be no assurance that we will have sufficient assets to repay the indebtedness. The operating and financial restrictions and covenants in these debt agreements and any future financing agreements may adversely affect our ability to finance future operations or capital needs or to engage in other business activities.

A default under ENLC's credit facility could have an adverse effect on the price of our common units and could result in a change of control of our general partner.

ENLC has entered into a credit facility that is secured by, among other things, a first priority lien on 88,528,451 of our common units and the 100% membership interest in our general partner indirectly held by ENLC. Although we are not a party to this credit facility, if a default under such credit facility were to occur, the lenders could foreclose on the pledged equity interests. Any such foreclosure on our common units could have an adverse effect on the market price of our common units. In addition, any foreclosure on ENLC's interest in the general partner would allow the new owner of our general partner to replace the board of directors and officers of our general partner with its own designees and to control the decisions taken by the board of directors and officers. Moreover, any change of control of our general partner (i) would permit the lenders under our credit facility to declare all amounts thereunder immediately due and payable and (ii) may permit the holders of our 7.125% Senior Notes due 2022 to require us to repurchase such notes. If any such event occurs, we may be required to refinance our debt on unfavorable terms, which could negatively impact our results of operations and our ability to make distributions to our unitholders.

Increases 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.

Interest rates on future credit facilities and debt offerings could be higher than current levels, causing our financing costs to increase accordingly. As with other yield-oriented securities, our unit price is impacted by our level of cash distributions and implied distribution yield. The distribution yield is often used by investors to compare and rank yield-oriented securities for investment decision-making purposes. Therefore, changes in interest rates, either positive or negative, 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 equity or incur debt for acquisitions or other purposes and our ability to make cash distributions at our intended levels or at all.

We are vulnerable to operational, regulatory and other risks due to our significant assets in south Louisiana and the Gulf of Mexico, including the effects of adverse weather conditions such as hurricanes.

Our operations and revenues will be significantly impacted by conditions in south Louisiana and the Gulf of Mexico because we have significant assets located in these two areas. Our concentration of activity in Louisiana and the Gulf of Mexico makes us more vulnerable than many of our competitors to the risks associated with these areas, including:

- adverse weather conditions, including hurricanes and tropical storms;
- delays or decreases in production, the availability of equipment, facilities or services; and
- changes in the regulatory environment.

Because a significant portion of our operations could experience the same condition at the same time, these conditions could have a relatively greater impact on our results of operations than they might have on other midstream companies that have operations in more diversified geographic areas.

A reduction in demand for NGL products by the petrochemical, refining or other industries or by the fuel markets could materially adversely affect our financial condition, results of operations or cash flows.

The NGL products we produce have a variety of applications, including as heating fuels, petrochemical feedstocks and refining blend stocks. A reduction in demand for NGL products, whether because of general or industry specific economic conditions, new government regulations, global competition, reduced demand by consumers for products made with NGL products (for example, reduced petrochemical demand observed due to lower activity in the automobile and construction industries), increased competition from petroleum-based feedstocks due to pricing differences, mild winter weather for some NGL applications or other reasons could result in a decline in the volume of NGL products we handle or reduce the fees we charge for our services. Our NGL products and the demand for these products are affected as follows:

- *Ethane.* Ethane is typically supplied as purity ethane or as part of ethane-propane mix. Ethane is primarily used in the petrochemical industry as feedstock for ethylene, one of the basic building blocks for a wide range of plastics and other chemical products. Although ethane is typically extracted as part of the mixed NGL stream at gas processing plants, if natural gas prices increase significantly in relation to NGL product prices or if the demand for ethylene falls, it may be more profitable for natural gas processors to leave the ethane in the natural gas stream. Such "ethane rejection," which we have experienced in greater volumes, reduces the volume of NGLs delivered for fractionation and marketing.

- *Propane.* Propane is used as a petrochemical feedstock in the production of ethylene and propylene, as a heating, engine and industrial fuel, and in agricultural applications such as crop drying. Changes in demand for ethylene and propylene could adversely affect demand for propane. The demand for propane as a heating fuel is significantly affected by weather conditions. The volume of propane sold is at its highest during the six-month peak heating season of October through March. Demand for our propane may be reduced during periods of warmer-than-normal weather.

- *Normal Butane.* Normal butane is used in the production of isobutane, as a refined product blending component, as a fuel gas, and in the production of ethylene and propylene. Changes in the composition of refined products resulting from governmental regulation, changes in feedstocks, products and economics, demand for heating fuel and for ethylene and propylene could adversely affect demand for normal butane.

- *Isobutane.* Isobutane is predominantly used in refineries to produce alkylates to enhance octane levels. Accordingly, any action that reduces demand for motor gasoline or demand for isobutane to produce alkylates for octane enhancement might reduce demand for isobutane.

- *Natural Gasoline.* Natural gasoline is used as a blending component for certain refined products and as a feedstock used in the production of ethylene and propylene. Changes in the mandated composition resulting from governmental regulation of motor gasoline and in demand for ethylene and propylene could adversely affect demand for natural gasoline.

NGLs and products produced from NGLs are sold in competitive global markets. Any reduced demand for ethane, propane, normal butane, isobutane or natural gasoline in the markets we access for any of the reasons stated above could adversely affect demand for the services we provide as well as NGL prices, which would negatively impact our financial condition, results of operations or cash flows.

We expect to encounter significant competition in any new geographic areas into which we seek to expand, and our ability to enter such markets may be limited.

If we expand our operations into new geographic areas, we expect to encounter significant competition for natural gas, condensate, NGLs and crude oil supplies and markets. Competitors in these new markets will include companies larger than us, which have both lower cost of capital and greater geographic coverage, as well as smaller companies, which have lower total cost structures. As a result, we may not be able to successfully develop greenfield or acquire assets located in new geographic areas and our results of operations could be adversely affected.

We do not own most of the land on which our pipelines, compression and plant facilities are located, which could disrupt our operations.

We do not own most of the land on which our pipelines, compression and plant facilities are located, 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 leases or if such rights-of-way or leases lapse or terminate. We sometimes obtain the rights to land owned by third parties and governmental agencies for a specific period of time. Our loss of these rights, through our inability to renew right-of-way contracts, leases or otherwise, could cause us to cease operations on the affected land, increase costs related to continuing operations elsewhere and reduce our revenue.

We offer pipeline, truck, rail and barge services. Significant delays, inclement weather or increased costs affecting these transportation methods could materially affect our results of operations.

We offer pipeline, truck, rail and barge services. The costs of conducting these services could be negatively affected by factors outside of our control, including rail service interruptions, new laws and regulations, rate increases, tariffs, rising fuel costs or capacity constraints. Inclement weather, including hurricanes, tornadoes, snow, ice and other weather events, can negatively impact our distribution network. In addition, rail, truck or barge accidents involving the transportation of hazardous materials could result in significant environmental penalties and remediation, claims arising from personal injury and property damage.

We could experience increased severity or frequency of trucking accidents and other claims, which could materially affect our results of operations.

Potential liability associated with accidents in the trucking industry is severe and occurrences are unpredictable. A material increase in the frequency or severity of accidents or workers' compensation claims or the unfavorable development of existing claims could materially adversely affect our results of operations. In the event that accidents occur, we may be unable to obtain desired contractual indemnities, and our insurance may be inadequate in certain cases. The occurrence of an event not fully insured or indemnified against, or the failure or inability of a customer or insurer to meet its indemnification or insurance obligations, could result in substantial losses.

Changes in trucking regulations may increase our costs and negatively impact our results of operations.

Our trucking services are subject to regulation as motor carriers by the DOT and by various state agencies, whose regulations include certain permit requirements of state highway and safety authorities. These regulatory authorities exercise broad powers over our trucking operations, generally governing such matters as the authorization to engage in motor carrier operations, safety, equipment testing and specifications and insurance requirements. There are additional regulations specifically relating to the trucking industry, including testing and specification of equipment and product handling requirements. The trucking industry is subject to possible regulatory and legislative changes that may impact our operations and affect the economics of the industry by requiring changes in operating practices or by changing the demand for or the cost of providing trucking services. Some of these possible changes include increasingly stringent fuel emission limits, changes in the regulations that govern the amount of time a driver may drive or work in any specific period, limits on vehicle weight and size and other matters, including safety requirements.

If we do not make acquisitions on economically acceptable terms or efficiently and effectively integrate the acquired assets with our asset base, our future growth will be limited.

Our ability to grow depends, in part, on our ability to make acquisitions that result in an increase in cash generated from operations on a per unit basis. If we are unable to make accretive acquisitions either because we are (1) unable to identify attractive acquisition candidates or negotiate acceptable purchase contracts with them, (2) unable to obtain financing for these acquisitions on economically acceptable terms or at all or (3) outbid by competitors, then our future growth and our ability to increase distributions will be limited.

From time to time, we may evaluate and seek to acquire assets or businesses that we believe complement our existing business and related assets. We may acquire assets or businesses that we plan to use in a manner materially different from their prior owner's use. Any acquisition involves potential risks, including:

- the inability to integrate the operations of recently acquired businesses or assets, especially if the assets acquired are in a new business segment or geographic area;
- the diversion of management's attention from other business concerns;
- the failure to realize expected volumes, revenues, profitability or growth;
- the failure to realize any expected synergies and cost savings;
- the coordination of geographically disparate organizations, systems and facilities;
- the assumption of unknown liabilities;
- the loss of customers or key employees from the acquired businesses;
- a significant increase in our indebtedness; and
- potential environmental or regulatory liabilities and title problems.

Management's assessment of these risks is inexact and may not reveal or resolve all existing or potential problems associated with an acquisition. Realization of any of these risks could adversely affect our operations and cash flows. If we consummate any future acquisition, our capitalization and results of operations may change significantly, and you will not have the opportunity to evaluate the economic, financial and other relevant information that we will consider in determining the application of these funds and other resources.

We may not be able to retain existing customers or acquire new customers, which would reduce our revenues and limit our future profitability.

The renewal or replacement of existing contracts with our customers at rates sufficient to maintain current revenues and cash flows depends on a number of factors beyond our control, including competition from other midstream service providers, and the price of, and demand for, crude oil, condensate, NGLs and natural gas in the markets we serve. The inability of our management to renew or replace our current contracts as they expire and to respond appropriately to changing market conditions could have a negative effect on our profitability.

In particular, our ability to renew or replace our existing contracts with industrial end-users and utilities impacts our profitability. For the year ended December 31, 2016, approximately 50.5% of our sales of gas transported using our physical facilities were to industrial end-users and utilities. As a consequence of the increase in competition in the industry and volatility of natural gas prices, industrial end-users and utilities may be reluctant to enter into long-term purchase contracts. Many industrial end-users purchase natural gas from more than one natural gas company and have the ability to change providers at any time. Some of these industrial end-users also have the ability to switch between gas and alternate fuels in response to relative price fluctuations in the market. Because there are numerous companies of greatly varying size and financial capacity that compete with us in marketing natural gas, we often compete in the industrial end-user and utilities markets primarily on the basis of price.

We are exposed to the credit risk of our customers and counterparties, and a general increase in the nonpayment and nonperformance by our customers could have an adverse effect on our financial condition, results of operations or cash flows.

Risks of nonpayment and nonperformance by our customers are a major concern in our business. We are subject to risks of loss resulting from nonpayment or nonperformance by our customers and other counterparties, such as our lenders and hedging counterparties. Any increase in the nonpayment and nonperformance by our customers could adversely affect our results of operations and reduce our ability to make distributions to our unitholders. Additionally, equity values for many of our customers continue to be low. The combination of a reduction in cash flow from lower commodity prices, a reduction in borrowing bases under reserve-based credit facilities and the lack of availability of debt or equity financing may result in a significant reduction in our customers' liquidity and 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.

Increased federal, state and local legislation and regulatory initiatives, as well as government reviews relating to hydraulic fracturing could result in increased costs and reductions or delays in natural gas production by our customers, which could adversely impact our revenues.

A portion of our suppliers' and customers' natural gas production is developed from unconventional sources, such as deep gas shales, that require hydraulic fracturing as part of the completion process. State legislatures and agencies have enacted legislation and promulgated rules to regulate hydraulic fracturing, require disclosure of hydraulic fracturing chemicals, temporarily or permanently ban hydraulic fracturing and impose additional permit requirements and operational restrictions in certain jurisdictions or in environmentally sensitive areas. EPA and the BLM have also issued rules, conducted studies and made proposals that, if implemented, could either restrict the practice of hydraulic fracturing or subject the process to further regulation. For instance, the EPA has issued final regulations under the federal Clean Air Act establishing performance standards, including standards for the capture of air emissions released during hydraulic fracturing and adopted rules prohibiting the discharge of wastewater from hydraulic fracturing operations to publicly owned wastewater treatment plants. The BLM also adopted new rules, effective on January 17, 2017, to reduce venting, flaring and leaks during oil and natural gas production activities on onshore federal and Indian leases. State and federal regulatory agencies also have recently focused on a possible connection between the operation of injection wells used for oil and gas waste waters and an observed increase in induced seismicity, which has resulted in some regulation at the state level. As regulatory agencies continue to study induced seismicity, additional legislative and regulatory initiatives could affecting our customers injection well operations as well as our brine disposal operations.

We cannot predict whether any additional legislation or regulations will be enacted and, if so, what the provisions would be. If additional levels of regulation and permits were required through the adoption of new laws and regulations at the federal or state level, that could lead to delays, increased operating costs and process prohibitions for our suppliers and customers that could reduce the volumes of natural gas that move through our gathering systems which could materially adversely affect our revenue and results of operations.

Transportation on certain of our natural gas pipelines is subject to federal and state rate and service regulation, which could limit the revenues we collect from our customers and adversely affect the cash available for distribution to our unitholders. The imposition of regulation on our currently unregulated natural gas pipelines also could increase our operating costs and adversely affect the cash available for distribution to our unitholders.

The rates, terms and conditions of service under which we transport natural gas in our pipeline systems in interstate commerce are subject to regulation of by FERC under the NGA and Section 311 of the NGPA and the rules and regulations promulgated under those statutes. Under the NGA, FERC regulation requires that interstate natural gas pipeline rates be filed with FERC and that these rates be "just and reasonable," not unduly preferential and not unduly discriminatory, although negotiated or settlement rates may be accepted in certain circumstances. Interested persons may challenge proposed new or changed rates, and FERC is authorized to suspend the effectiveness of such rates pending an investigation or hearing. FERC may also investigate, upon complaint or on its own motion, rates that are already in effect and may order a pipeline to change its rates prospectively. Accordingly, action by FERC could adversely affect our ability to establish reasonable rates that cover operating costs and allow for a reasonable return. An adverse determination in any future rate proceeding brought by or against us could have a material adverse effect on our business, financial condition, results of operations, and cash available for distribution. Under the NGPA, we are required to justify our rates for interstate transportation service on a cost-of-service basis every five years. Our intrastate natural gas pipeline operations are subject to regulation by various agencies of the states in which they are located. Should FERC or any of these state agencies determine that our rates for Section 311 transportation service or intrastate transportation service should be lowered, our business could be adversely affected.

The rates charged by our natural gas pipelines may also be affected by the ongoing uncertainty regarding FERC's current income tax allowance policy. There is not likely to be a definitive resolution of these income tax allowance issues for some time, and the ultimate outcome of this proceeding is not certain and could result in changes going forward to FERC's treatment of income tax allowances in the cost of service or to the discounted cash flow return on equity. Depending upon the resolution of these issues, the cost of service rates of our interstate natural gas pipelines could be affected to the extent it proposes new rates or changes to its existing rates or if its rates are subject to compliance or challenged by FERC.

Our natural gas gathering and processing activities generally are exempt from FERC regulation under the Natural Gas Act. However, the distinction between FERC-regulated transmission services and federally unregulated gathering services is the subject of substantial, ongoing litigation, so the classification and regulation of our gathering facilities are subject to change based on future determinations by FERC and the courts. Natural gas gathering may receive greater regulatory scrutiny at both the state and federal levels since FERC has less extensively regulated the gathering activities of interstate pipeline transmission companies and a number of such companies have transferred gathering facilities to unregulated affiliates. Our gathering operations also may be or become subject to safety and operational regulations relating to the design, installation, testing, construction, operation, replacement and management 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 our operations, but the industry could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes.

If we fail to comply with all the applicable FERC-administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines. Under the EPAct 2005, FERC has civil penalty authority to impose penalties for current violations of the NGA or NGPA of up to $1.0 million per day for each violation. The maximum penalty authority established by statute has been and will continue to be adjusted periodically for inflation. FERC also has the power to order disgorgement of profits from transactions deemed to violate the NGA and EPAct 2005.

Other state and local regulations also affect our business. We are subject to some ratable take and common purchaser statutes in the states where we operate. 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 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. Federal law leaves any economic regulation of natural gas gathering to the states, and some of the states in which we operate have adopted complaint-based or other limited economic regulation of natural gas gathering activities. States in which we operate that have adopted some form of complaint-based regulation, like Texas, generally allow natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to natural gas gathering access and rate discrimination.

Transportation on our liquids pipelines is subject to federal and state rate and service regulation, which could limit the revenues we collect from our customers and adversely affect the cash available for distribution to our unitholders.

Our interstate liquids transportation pipelines are subject to regulation by FERC under the ICA, the Energy Policy Act of 1992 and the rules and regulations promulgated under those laws. If, upon completion of an investigation, FERC finds that the new or changed rates are unlawful, it is authorized to require the pipeline to refund revenues collected in excess of the just and reasonable rates during the term of the investigation. FERC may also investigate, upon complaint or on its own motion, rates that are already in effect and may order a carrier to change its rates prospectively. Under certain circumstances, FERC could limit our recovery of costs or could require us to reduce our rates and the payment of reparations to complaining shippers for up to two years prior to the date of the complaint. In particular, ongoing uncertainty surrounding FERC’s current income tax allowance policy could affect our rates going forward. FERC also has the authority to change our terms and conditions of service if it determines that they are unjust and unreasonable or unduly discriminatory or preferential.

Changes to FERC’s annual indexing methodology, including adoption of a policy that would deny proposed index increases for pipelines under certain circumstances where revenues exceed cost-of-service numbers by a certain percentage or where the proposed index increases exceed certain annual cost changes could have a material impact on our business. Such changes, if accepted, could decrease our rates and adversely affect our business.

As we acquire, construct and operate new liquids assets and expand our liquids transportation business, the classification and regulation of our liquids transportation services are subject to ongoing assessment and change based on the services we provide and determinations by FERC and the courts. Such changes may subject additional services we provide to regulation by FERC, which could increase our operating costs, decrease our rates and adversely affect our business.

We may incur significant costs and liabilities resulting from compliance with pipeline safety regulations.

The pipelines we own and operate are subject to stringent and complex regulation related to pipeline safety and integrity management. For instance, the Department of Transportation, through PHMSA, has established a series of rules that require pipeline operators to develop and implement integrity management programs for hazardous liquid (including oil) pipeline segments that, in the event of a leak or rupture, could affect HCAs. PHMSA also recently proposed rulemaking that would expand existing integrity management requirements to natural gas transmission and gathering lines in areas with medium population densities. Additional action by PHMSA with respect to pipeline integrity management requirements may occur in the future. At this time, we cannot predict the cost of such requirements, but they could be significant. Moreover, violations of pipeline safety regulations can result in the imposition of significant penalties.

Several states have also passed legislation or promulgated rules to address pipeline safety. Compliance with pipeline integrity laws and other pipeline safety regulations issued by state agencies such as the TRRC could result in substantial expenditures for testing, repairs and replacement. For example, TRRC regulations require periodic testing of all intrastate pipelines meeting certain size and location requirements. Our costs relating to compliance with the required testing under the TRRC regulations were approximately $3.3 million, $3.3 million, and $2.5 million for the years ended December 31, 2016, 2015 and 2014, respectively. If our pipelines fail to meet the safety standards mandated by the TRRC or the DOT regulations, then we may be required to repair or replace sections of such pipelines or operate the pipelines at a reduced maximum allowable operating pressure, the cost of which cannot be estimated at this time.

Due to the possibility of new or amended laws and regulations or reinterpretation of existing laws and regulations, there can be no assurance that future compliance with PHMSA or state requirements will not have a material adverse effect on our results of operations or financial positions. Because certain of our operations are located around urban or more populated areas, such as the Barnett Shale, we may incur additional expenses to mitigate noise, odor and light that may be emitted in our operations and expenses related to the appearance of our facilities. Municipal and other local or state regulations are imposing various obligations including, among other things, regulating the location of our facilities, imposing limitations on the noise levels of our facilities and requiring certain other improvements that increase the cost of our facilities. We are also subject to claims by neighboring landowners for nuisance related to the construction and operation of our facilities, which could subject us to damages for declines in neighboring property values due to our construction and operation of facilities.

Failure to comply with existing or new environmental laws or regulations or an accidental release of hazardous substances, hydrocarbons or wastes into the environment may cause us to incur significant costs and liabilities.

Many of the operations and activities of our pipelines, gathering systems, processing plants, fractionators, brine disposal operations and other facilities are subject to significant federal, state and local environmental laws and regulations, the violation of which can result in administrative, civil and criminal penalties, including civil fines, injunctions or both. The obligations imposed by these laws and regulations include obligations related to air emissions and discharge of pollutants from our pipelines and other facilities and the cleanup of hazardous substances and other wastes that are or may have been released at properties currently or previously owned or operated by us or locations to which we have sent wastes for treatment or disposal. These laws impose strict, joint and several liability for the remediation of contaminated areas. Private parties, including the owners of properties near our facilities or upon or through which our gathering systems traverse, may also have the right to pursue legal actions to enforce compliance and to seek damages for non-compliance with environmental laws for releases of contaminants or for personal injury or property damage.

Our business may be adversely affected by increased costs due to stricter pollution control requirements or liabilities resulting from non-compliance with required operating or other regulatory permits. New environmental laws or regulations, including, for example, legislation relating to the control of greenhouse gas emissions, or changes in existing environmental laws or regulations might adversely affect our products and activities, including processing, storage and transportation, as well as waste management and air emissions. Federal and state agencies could also impose additional safety requirements, any of which could affect our profitability. Changes in laws or regulations could also limit our production or the operation of our assets or adversely affect our ability to comply with applicable legal requirements or the demand for crude oil, brine disposal services or natural gas, which could adversely affect our business and our profitability.

Recent rules under the Clean Air Act imposing more stringent requirements on the oil and gas industry could cause our customers and us to incur increased capital expenditures and operating costs as well as reduce the demand for our services.

We are subject to stringent and complex regulation under the federal Clean Air Act, implementing regulations, and state and local equivalents, including regulations related to controls for oil and natural gas production, pipelines, and processing operations. For instance, the EPA finalized new rules, effective August 2, 2016, to regulate emissions of methane and volatile organic compounds from new and modified sources in the oil and gas sector. EPA also finalized a rule regarding the alternative criteria for aggregating multiple small surface sites into a single source for air quality permitting purposes. This rule could cause small facilities, on an aggregate basis, to be deemed a major source, thereby triggering more stringent air permitting processes and requirements across the oil and gas industry. In addition, on November 10, 2016, the EPA issued a final Information Collection Request ("ICR") that requires numerous oil and gas companies to provide information regarding methane emissions from existing oil and gas facilities, a step used to provide a basis for future rulemaking. The BLM also adopted new rules on November 15, 2016, effective January 17, 2017, to reduce venting, flaring, and leaks during oil and natural gas production activities on onshore federal and Indian leases.

Additional regulation of GHG emissions from the oil and gas industry remains a possibility. These regulations could require a number of modifications to our operations, and our natural gas exploration and production suppliers' and customers' operations, including the installation of new equipment, which could result in significant costs, including increased capital expenditures and operating costs. The incurrence of such expenditures and costs by our suppliers and customers could result in reduced production by those suppliers and customers and thus translate into reduced demand for our services. Responding to rule challenges, the EPA has since revised certain aspects of its April 2012 rules and has indicated that it may reconsider other aspects of the rules.

Climate change legislation and regulatory initiatives could result in increased operating costs and reduced demand for the natural gas and NGL services we provide.

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. In addition, 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 adoption of the Paris Agreement. The Paris Agreement entered into force November 4, 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. At the federal regulatory level, both the EPA and the BLM have adopted regulations for the control of methane emissions, which also include leak detection and repair requirements, from the oil and gas industry.

In addition, many states have already taken legal measures to reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. Most of these cap and trade programs work by requiring either major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and NGL fractionation plants, to acquire and surrender emission allowances with the number of allowances available for purchase reduced each year until the overall GHG emission reduction goal is achieved.

Although it is not possible at this time to predict whether future legislation or new regulations may be adopted to address greenhouse gas emissions or how such measures would impact our business, the adoption of legislation or regulations imposing reporting or permitting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur additional costs to reduce emissions of GHGs associated with our operations, could adversely affect our performance of operations in the absence of any permits that may be required to regulate emission of GHGs or could adversely affect demand for the natural gas we gather, process or otherwise handle in connection with our services.

The Endangered Species Act and Migratory Bird Treaty Act govern our operations and additional restrictions may be imposed in the future, which could have an adverse impact on our operations.

The ESA and analogous state laws restrict activities that may affect endangered or threatened species or their habitats. Similar protections are offered to migratory birds under the MBTA. The U.S. Fish and Wildlife Service and state agencies may designate critical or suitable habitat areas that they believe are necessary for the survival of threatened or endangered species, which could materially restrict use of or access to federal, state and private lands. Some of our operations may be located in areas that are designated as habitats for endangered or threatened species or that may attract migratory birds. In these areas, we may be obligated to develop and implement plans to avoid potential adverse impacts to protected species, and we may be prohibited from conducting operations in certain locations or during certain seasons, such as breeding and nesting seasons, when our operations could have an adverse effect on the species. It is also possible that a federal or state agency could order a complete halt to our activities in certain locations if it is determined that such activities may have a serious adverse effect on a protected species. In addition, the U.S. Fish and Wildlife Service and state agencies regularly review species that are listing candidates, and designations of additional endangered or threatened species, or critical or suitable habitat, under the ESA could cause us to incur additional costs or become subject to operating restrictions or bans in the affected areas.

Our business involves many hazards and operational risks, some of which may not be fully covered by insurance. The occurrence of a significant accident or other event that is not fully insured could adversely affect our operations and financial condition.

Our operations are subject to the many hazards inherent in the gathering, compressing, processing, transporting, fractionating, disposing and storage of natural gas, NGLs, condensate, crude oil and brine, including:

- damage to pipelines, related equipment and surrounding properties caused by hurricanes, floods, fires and other natural disasters and acts of terrorism;
- inadvertent damage from construction and farm equipment;
- leaks of natural gas, NGLs, crude oil, condensate and other hydrocarbons;
- induced seismicity;
- rail accidents, barge accidents and truck accidents; and
- fires and explosions.

These risks could result in substantial losses due to personal injury and/or loss of life, severe damage to and destruction of property and equipment and pollution or other environmental damage and may result in curtailment or suspension of our related operations. We are not fully insured against all risks incident to our business. In accordance with typical industry practice, we have appropriate levels of business interruption and property insurance on our underground pipeline systems. We are not insured against all environmental accidents that might occur. If a significant accident or event occurs that is not fully insured, it could adversely affect our operations and financial condition.

The adoption of derivatives legislation by the United States Congress and promulgation of related regulations could have an adverse effect on our ability to hedge risks associated with our business.

Comprehensive financial reform legislation was signed into law by the President on July 21, 2010. The legislation calls for the Commodities Futures Trading Commission (“CFTC”) to regulate certain markets for derivative products, including over-the-counter (“OTC”) derivatives. The CFTC has issued several new relevant regulations and other rulemakings are pending at the CFTC, the product of which would be rules that implement the mandates in the new legislation to cause significant portions of derivatives markets to clear through clearinghouses. While some of these rules have been finalized, some have not and, as a result, the final form and timing of the implementation of the new regulatory regime affecting commodity derivatives remains uncertain.

In particular, on October 18, 2011, the CFTC adopted final rules under the Dodd-Frank Act establishing position limits for certain energy commodity futures and options contracts and economically equivalent swaps, futures and options. The position limit levels set the maximum amount of covered contracts that a trader may own or control separately or in combination, net long or short. The final rules also contained limited exemptions from position limits which would be phased in over time for certain bona fide hedging transactions and positions. The CFTC’s original position limits rule was challenged in court by two industry associations and was vacated and remanded by a federal district court. However, in November 2013, the CFTC proposed new rules that would place limits on positions in certain core futures and equivalent swaps contracts for or linked to certain physical commodities, subject to exceptions for certain bona fide hedging transactions. The CFTC has sought comment on the position limits rule as reproposed, but these new position limit rules are not yet final and the impact of those provisions on us is uncertain at this time. The CFTC has withdrawn its appeal of the court order vacating the original position limits rule.

The legislation and new regulations may also require counterparties to our derivative instruments to spin off some of their derivatives activities to separate entities, which may not be as creditworthy as the current counterparties. The new legislation and any new regulations could significantly increase the cost of derivative contracts, materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives 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 to generate sufficient cash flow to pay quarterly distributions at current levels or at all. Our revenues could be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material, adverse effect on us, our financial condition and our results of operations.

Our use of derivative financial instruments does not eliminate our exposure to fluctuations in commodity prices and interest rates and has in the past and could in the future result in financial losses or reduce our income.

Our operations expose us to fluctuations in commodity prices, and our credit facility exposes us to fluctuations in interest rates. We use over-the-counter price and basis swaps with other natural gas merchants and financial institutions. Use of these instruments is intended to reduce our exposure to short-term volatility in commodity prices. As of December 31, 2016, we have hedged only portions of our expected exposures to commodity price risk. In addition, to the extent we hedge our commodity price risk using swap instruments, we will forego the benefits of favorable changes in commodity prices. Although we do not currently have any financial instruments to eliminate our exposure to interest rate fluctuations, we may use financial instruments in the future to offset our exposure to interest rate fluctuations.

Even though monitored by management, our hedging activities may fail to protect us and could reduce our earnings and cash flow. Our hedging activity may be ineffective or adversely affect cash flow and earnings because, among other factors:

- hedging can be expensive, particularly during periods of volatile prices;
- our counterparty in the hedging transaction may default on its obligation to pay or otherwise fail to perform; and
- available hedges may not correspond directly with the risks against which we seek protection. For example:
  - the duration of a hedge may not match the duration of the risk against which we seek protection;
  - variations in the index we use to price a commodity hedge may not adequately correlate with variations in the index we use to sell the physical commodity (known as basis risk); and
  - we may not produce or process sufficient volumes to cover swap arrangements we enter into for a given period. If our actual volumes are lower than the volumes we estimated when entering into a swap for the period, we might be forced to satisfy all or a portion of our derivative obligation without the benefit of cash flow from our sale or purchase of the underlying physical commodity, which could adversely affect our liquidity.

A failure in our computer systems or a terrorist or cyber-attack on us, or third parties with whom we have a relationship, may adversely affect our ability to operate our business.

We are reliant on technology to conduct our businesses. Our business is dependent upon our operational and financial computer systems to process the data necessary to conduct almost all aspects of our business, including operating our pipelines, truck fleet and storage facilities, recording and reporting commercial and financial transactions and receiving and making payments. Any failure of our computer systems, or those of our customers, suppliers or others with whom we do business, could materially disrupt our ability to operate our business. Unknown entities or groups have mounted so-called “cyber-attacks” on businesses to disable or disrupt computer systems, disrupt operations and steal funds or data. 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. In addition, our pipeline systems may be targets of terrorist activities that could disrupt our ability to conduct our business and have a material adverse effect on our business and results of operations. Strategic targets, such as energy-related assets, may be at greater risk of future terrorist or cyber-attacks than other targets in the United States. Our insurance may not protect us against such occurrences. Any such terrorist or cyber-attack that affects us or our customers, suppliers or others with whom we do business, could have a material adverse effect on our business, cause us to incur a material financial loss, subject us to possible legal claims and liability and/or damage our reputation.

Moreover, as the sophistication of cyber attacks continues to evolve, we may be required to expend significant additional resources to further enhance our digital security or to remediate vulnerabilities. In addition, cyber-attacks against us or others in our industry could result in additional regulations, which could lead to increased regulatory compliance costs, insurance coverage cost or capital expenditures. We cannot predict the potential impact to our business or the energy industry resulting from additional regulations

Our success depends on key members of our management, the loss or replacement of whom could disrupt our business operations.

We depend on the continued employment and performance of the officers of our general partner and key operational personnel. If any of these officers or other key personnel resign or become unable to continue in their present roles and are not adequately replaced, our business operations could be materially adversely affected. We do not maintain any “key man” life insurance for any officers.

Failure to attract and retain an appropriately qualified workforce could reduce labor productivity and increase labor costs, which could have a material adverse effect on our business and results of operations.

Gathering and compression services require laborers skilled in multiple disciplines, such as equipment operators, mechanics and engineers, among others. 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.

Subsidence and coastal erosion could damage our pipelines along the Gulf Coast and offshore and the facilities of our customers, which could adversely affect our operations and financial condition.

Our pipeline operations along the Gulf Coast and offshore could be impacted by subsidence and coastal erosion. Such processes could cause serious damage to our pipelines, which could affect our ability to provide transportation services. Additionally, such processes could impact our customers who operate along the Gulf Coast, and they may be unable to utilize our services. Subsidence and coastal erosion could also expose our operations to increased risks associated with severe weather conditions, such as hurricanes, flooding and rising sea levels. As a result, we may incur significant costs to repair and preserve our pipeline infrastructure. Such costs could adversely affect our financial condition, results of operation or cash flows.

Our assets were constructed over many decades using varying construction and coating techniques, which may cause our inspection, maintenance or repair costs to increase in the future. In addition, there could be service interruptions due to unknown events or conditions or increased downtime associated with our pipelines that could have a material adverse effect on our financial condition, results of operations or cash flows.

Our pipelines were constructed over many decades. Pipelines are generally long-lived assets, and pipeline construction and coating techniques have varied over time and can vary for individual pipelines. Depending on the era of construction era and quality, some assets will require more frequent inspections or repairs, which could result in increased maintenance or repair expenditures in the future. Any significant increase in these expenditures could adversely affect our financial condition, results of operations, or cash flows.

Risk Inherent in an Investment in the Partnership

Cash distributions are not guaranteed and may fluctuate with our performance and the establishment of financial reserves.

Because distributions on our units are dependent on the amount of cash we generate, distributions may fluctuate based on our performance. The actual amount of cash that is available to be distributed each quarter will depend on numerous factors, some of which are beyond our control and the control of our general partner. Cash distributions are dependent primarily on cash flow, including cash flow from financial reserves and working capital borrowings and not solely on profitability, which is affected by non-cash items. Therefore, cash distributions might be made during periods when we record losses and might not be made during periods when we record profits.

We may not have sufficient available cash from operating surplus each quarter to enable us to make cash distributions at our current distribution rate under our cash distribution policy. 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 we charge and the margins we realize for our services;
- the prices of, levels of production of and demand for crude oil, natural gas, condensate and NGLs;
- the volume of natural gas we gather, compress, process, transport and sell, the volume of NGLs we process or fractionate and sell, the volume of crude oil we handle at our crude terminals, the volume of crude oil we gather, transport, purchase and sell, the volume of condensate we stabilize and transport and the volumes of brine we dispose;
- the relationship between natural gas and NGL prices;
- cash settlements of hedging positions;
- the level of competition from other midstream energy companies;
- the level of our operating and maintenance 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, some of which are beyond our control, including:

- the level of capital expenditures we make;
- our ability to make borrowings under our credit facility to pay distributions;
- the cost of acquisitions;
- our debt service requirements and other liabilities;
- fluctuations in our working capital needs;
- general and administrative expenses;
- restrictions on distributions contained in our debt agreements; and
- the amount of cash reserves established by our general partner for the proper conduct of our business.

Devon, through its control of ENLC, controls our general partner, which has sole responsibility for conducting our business and managing our operations. Devon, ENLC and our general partner have conflicts of interest with, and may favor Devon's interests to the detriment of, our unitholders.

Devon, through its control of ENLC, controls our general partner and indirectly has the power to appoint all of the officers and directors of our general partner. Although our general partner has a fiduciary duty to manage us in a manner that is beneficial to us and our unitholders, the directors and officers of our general partner have a fiduciary duty to manage our general partner in a manner that is beneficial to its owner, ENLC, in which Devon owns the manager and a 64.2% limited liability company interest as of December 31, 2016. Conflicts of interest may arise in the future among Devon, ENLC and its affiliates, including our general partner, on the one hand, and our partnership and our unitholders, on the other hand. As a result of these conflicts our general partner may favor its own interests and those of its affiliates, including Devon and ENLC, over our interests. These conflicts include, among others, the following situations:

Conflicts Relating to Control

- our partnership agreement limits our general partner's liability and reduces its fiduciary duties, while also restricting the remedies available to our unitholders for actions that might, without these limitations, constitute breaches of fiduciary duty by our general partner;
- in resolving conflicts of interest, our general partner is allowed to take into account the interests of parties in addition to unitholders, which has the effect of limiting its fiduciary duties to the unitholders;
- our general partner's affiliates may engage in limited competition with us;

Conflicts Relating to Costs

- our general partner determines the amount and timing of asset purchases and sales, capital expenditures, borrowings, issuance of additional limited partner interests and reserves;
- our general partner determines which costs incurred by it and its affiliates are reimbursable by us; and
- our general partner is not restricted from causing us to pay it or its affiliates for any services rendered on terms that are fair and reasonable to us or entering into additional contractual arrangements with any of these entities on our behalf.

Our unitholders will have limited voting rights and will not be entitled to elect our general partner or the board of directors of our general partner, which could reduce the price at which our common units will trade.

Unlike the holders of common stock in a corporation, unitholders have only limited voting rights on matters affecting our business, and therefore limited ability to influence management's decisions regarding our business. Unitholders did not elect our general partner or the board of directors of our general partner and have no right to elect our general partner or the board of directors of our general partner on an annual or other continuing basis. The board of directors of our general partner, including its independent directors, is chosen indirectly by ENLC, subject, in certain circumstances, to the designation rights of certain of our investors with respect to one director. In addition, the partnership agreement 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. As a result of these limitations, the price at which our common units trade could be diminished because of the absence or reduction of a takeover premium in the trading price.

Even if our unitholders are dissatisfied with the performance of our general partner, they have little ability to remove our general partner.

Our unitholders have little ability to remove our general partner because the general partner and its affiliates own a significant amount of our outstanding units. The vote of the holders of at least 66 2/3% of all outstanding common units voting together as a single class is required to remove the general partner. Affiliates of the general partner controlled approximately 46.1% of all the outstanding units as of February 8, 2017.

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

Unitholders' voting rights are further restricted by the partnership agreement, which provides that any units held by a person that owns 20.0% or more of any class of units then outstanding, other than our general partner, its affiliates, their transferees and persons who acquired such units with the prior approval of the board of directors of the general partner, cannot be voted on any matter.

Cost reimbursements due to our general partner and its affiliates for services provided, which will be determined by our general partner, could be substantial and would reduce the cash available for distribution to our unitholders.

Prior to making any distributions on the units, we reimburse our general partner and its affiliates, including officers and directors of our general partner, for all expenses they incur on our behalf. These expenses will include all costs incurred by our general partner and its affiliates in the discharge of their duties to our partnership, including costs for rendering corporate staff and support services to us, if any. There is no limit on the amount of expenses for which our manager and its affiliates may be reimbursed. Our partnership agreement provides that our general partner will determine the expenses that are allocable to us. In addition, to the extent our general partner incurs obligations on behalf of us, we are obligated to reimburse or indemnify our general partner. If we are unable or unwilling to reimburse or indemnify our general partner, our general partner may take actions to cause us to make payments of these obligations and liabilities. Any such payments could reduce the amount of cash otherwise available for distribution to our unitholders.

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

The general partner may transfer its general partner interest in us to a third party in a merger or in a sale of all or substantially all of its assets without the consent of the unitholders. Furthermore, there is no restriction in the partnership agreement on the ability of (i) ENLC to transfer all or a portion of its ownership interest in the general partner to a third party or (ii) Devon to transfer all or a portion of its ownership interest in ENLC and/or ENLC's manager to a third party. The new owner of the general partner or ENLC's manager, as the case may be, would then be in a position to replace the board of directors and officers of the general partner with its own choices and to control the decisions taken by the board of directors and officers.

Our general partner's absolute discretion in determining the level of cash reserves may adversely affect our ability to make cash distributions to our unitholders.

Our partnership agreement requires our general partner to deduct from operating surplus cash reserves that in its reasonable discretion are necessary to fund our future operating expenditures. In addition, the partnership agreement permits our general partner to reduce available cash by establishing cash reserves for the proper conduct of our business, to comply with applicable law or agreements to which we are a party or to provide funds for future distributions to partners. These cash reserves will affect the amount of cash available for distribution to our unitholders.

Our partnership agreement replaces the fiduciary duties otherwise owed to our unitholders by our general partner with contractual standards governing its duties and restricts the remedies available to our unitholders for actions that might otherwise constitute a breach of fiduciary duty by our general partner.

Our partnership agreement contains provisions that eliminate and replace the fiduciary standards that our general partner would otherwise be held to by state fiduciary duty law. 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, or otherwise, free of fiduciary duties to our unitholders. This entitles our general partner to consider only the interests and factors that it desires, and it has no duty or obligation to give any consideration to any interest of, or factors affecting our unitholders. Examples of decisions that our general partner may make in its individual capacity include:

- how to allocate business opportunities among us and its other affiliates;
- whether to exercise its call right;
- whether or not to consent to any merger or consolidation of us or any amendment to our partnership agreement; and
- whether or not the general partner should elect to seek the approval of the conflicts committee or the unitholders, or neither, of any conflicted transaction.

The partnership agreement also restricts the remedies available to our unitholders for actions that would otherwise constitute breaches of our general partner's fiduciary duties. By purchasing any of our common units, a unitholder is treated as having consented to the provisions in our partnership agreement, including the provisions discussed above.

We may issue additional units, including units that are senior to our common units, without our unitholders' approval, which would dilute our unitholders' ownership interests.

We may issue an unlimited number of limited partner interests of any type without the approval of our unitholders. The issuance of additional limited partner interests or other equity securities of equal or senior rank will have the following effects:

- our existing unitholders' proportionate ownership interest in us will decrease;
- the amount of cash available for distribution on each unit may decrease;

- the relative voting strength of each previously outstanding unit may be diminished; and
- the market price of the common units may decline.

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

If at any time our general partner and its affiliates own more than 80.0% of the common units, our general partner will have the right, but not the obligation, which it may assign to any of its affiliates or to us, to acquire all, but not less than all, of the common units held by unaffiliated persons at a price equal to the greater of (1) their then-current market price and (2) the highest per-unit price paid by our general partner or any of its affiliates for our common units during the 90-day period preceding the date such notice is first mailed. As a result, our unitholders may be required to sell their common units at an undesirable time or price and may therefore not receive any return on their investment. Existing unitholders may also incur a tax liability upon a sale of their units. Our general partner is not obligated to obtain a fairness opinion regarding the value of our common units to be repurchased by it upon exercise of the call right. There is no restriction in our partnership agreement that prevents our general partner from issuing additional common units and exercising its call right. If our general partner exercised its call right, the effect would be to take us private. As of December 31, 2016, ENLC and its affiliates, including Devon, owned 53.4% of our outstanding common units.

ENLC or its affiliates, including our largest holder Devon, may sell units in the public or private markets, and such sales could have an adverse impact on the trading price of the common units.

As of December 31, 2016, ENLC and its affiliates, including our largest holder Devon, held an aggregate of 183,189,051 units. The sale of any or all of these units in the public or private markets could have an adverse impact on the price of common units or on any trading market on which common units are held.

The price of our common units may fluctuate significantly, which could cause our unitholders to lose all or part of their investment.

As of December 31, 2016, only approximately 46.6% of our common units were held by public unitholders. The lack of liquidity may result in wide bid-ask spreads, contribute to significant fluctuations in the market price of our common units and limit the number of investors who are able to buy our common units. The market price of our common units may be influenced by many factors, some of which are beyond our control, including:

- the quarterly distributions paid by us with respect to our common units;
- our quarterly or annual earnings or those of other companies in our industry;
- the loss of Devon as a customer;
- events affecting Devon;
- announcements by us or our competitors of significant contracts or acquisitions;
- changes in accounting standards, policies, guidance, interpretations or principles;
- general economic conditions;
- the failure of securities analysts to cover our common units or changes in financial estimates by analysts;
- future sales of our common units; and
- other factors described in these “Risk Factors.”

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

Our unitholders could be held liable for our obligations to the same extent as a general partner if a court determined that the right or the exercise of the right by our unitholders to remove or replace our general partner, to approve amendments to our partnership agreement, or to take other action under our partnership agreement constituted participation in the “control” of our business, to the extent that a person who has transacted business with the Partnership reasonably believes, based on our unitholders’ conduct, that our unitholders are a general partner. Our general partner generally has unlimited liability for the obligations of our partnership, such as its debts and environmental liabilities, except for those contractual obligations of our partnership that are expressly made without recourse to our general partner. In addition, Section 17-607 of the Delaware Revised Uniform Limited Partnership Act (the “Delaware Act”) provides that a limited partner who receives a distribution and knew at the time of the distribution that the distribution was in violation of that section may be liable to the limited partnership for the amount of the distribution for a period of three years from the date of the distribution. 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 do business.

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 exempts us from the following corporate governance requirements:

- the requirement that a majority of the board consist of independent directors;
- the requirement that the board of directors have a nominating or corporate governance committee, composed entirely of independent directors, that is responsible for identifying individuals qualified to become board members, consistent with criteria approved by the board, selection of board nominees for the next annual meeting of equity holders, development of corporate governance guidelines and oversight of the evaluation of the board and management;
- the requirement that we have a compensation committee of the board, composed entirely of independent directors, that is responsible for reviewing and approving corporate goals and objectives relevant to chief executive officer compensation, evaluation of the chief executive officer’s performance in light of the goals and objectives, determination and approval of the chief executive officer’s compensation, making recommendations to the board with respect to compensation of other executive officers and incentive compensation and equity-based plans that are subject to board approval and producing a report on executive compensation to be included in an annual proxy statement or Form 10-K filed with the SEC;
- the requirement that we conduct an annual performance evaluation of the nominating, corporate governance and compensation committees; and
- the requirement that we have written charters for the nominating, corporate governance and compensation committees addressing the committees’ responsibilities and annual performance evaluations.

For so long as we remain a publicly traded limited partnership, we will not be required to have a majority of independent directors or nominating, corporate governance or compensation committees. 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 Act, a limited partnership cannot make a distribution to its limited partners if, after the distribution, all liabilities, other than liabilities to unitholders on account of their limited partner interests and liabilities for which the recourse of creditors is limited to specific property of the limited partnership, would exceed the fair value of the assets of the limited partnership. For the purpose of determining the fair value of the assets of a limited partnership, the Delaware Act provides that the fair value of property subject to liability for which recourse of creditors is limited shall be included in the assets of the limited partnership only to the extent that the fair value of that property exceeds the non-recourse liability. The Delaware Act provides that a limited partner who receives a distribution and knew at the time of the distribution that the distribution was in violation of the Delaware Act will be liable to the limited partnership for the amount of the distribution for three years.

Tax Risks to Our Unitholders

Our tax treatment depends on our status as a partnership for federal income tax purposes, as well as our not being subject to entity level taxation by individual states. If the IRS treats us as a corporation or we become subject to entity level taxation for state tax purposes, it would substantially reduce the amount of cash available for distribution to you.

The anticipated after-tax economic benefit of an investment in us depends largely on our being treated as a partnership for federal income tax purposes.

If we were treated as a corporation for federal income tax purposes, we would pay additional tax on our income at corporate rates of up to 35% (under the law as of the date of this report) and we would probably pay state income taxes as well. In addition, distributions to unitholders would generally be taxed again as corporate distributions and none of our income, gains, losses or deductions would flow through to unitholders. Because a tax would be imposed upon us as a corporation, the cash available for distribution to unitholders would be substantially reduced. Therefore, treatment of us as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to the unitholders and thus would likely result in a material reduction in the value of the common units.

In addition, recently enacted legislation applicable to partnership tax years beginning after 2017 changes the audit procedures for large partnerships and in certain circumstances would permit the IRS to assess and collect taxes (including any applicable penalties and interest) resulting from partnership-level federal income tax audits directly from us in the year in which the audit is completed. If we are required to make payments of taxes, penalties and interest resulting from audit adjustments, our cash available for distribution to our unitholders might be substantially reduced.

Moreover, changes in current state law may subject us to entity-level taxation by individual states. Because of widespread state budget deficits, several states are evaluating ways to subject partnerships to entity level taxation through the imposition of state income, franchise and other forms of taxation. For example, we are required to pay Texas franchise tax at a maximum effective rate of 0.75% of our taxable margin apportioned to Texas in the prior year. If additional state tax were to be imposed on us, the cash available for distribution to unitholders could be reduced and/or the value of an investment in our common units would be adversely impacted.

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 will be decreased to reflect the impact of that law on us. No such adjustments have been made to date, but there can be no assurance that no such adjustments will be made in the future.

If the IRS contests the federal income tax positions we take, the market for our common units may be adversely impacted and the costs of any contest could reduce the cash available for distribution to our unitholders.

We have not requested any ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes or any other matter affecting us. The IRS may adopt positions that differ from our counsel’s conclusions expressed in this annual report or from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of our counsel’s conclusions or the positions we take. A court may not agree with all of our counsel’s conclusions or the positions we take. Any contest with the IRS may materially and adversely impact the market for our common units and the prices at which our common units trade. In addition, our costs of any contest with the IRS will be borne by us and therefore indirectly by our unitholders and our general partner since such costs will reduce the amount of cash available for distribution by us.

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, in which case our cash available for distribution to our unitholders might be substantially reduced.

Pursuant to recently enacted legislation, if the IRS makes audit adjustments to income tax returns for tax years beginning after 2017, it may assess and collect taxes (including any applicable penalties and interest) directly from us in the year in which the audit is completed. If we are required to 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 for the taxable year in which the audit is completed, unitholders during that taxable year would bear the expense of the adjustment even if they were not unitholders during that taxable year.

Unitholders may be required to pay taxes on their share of our taxable income even if they do not receive any cash distributions from us.

Because our unitholders will be treated as partners to whom we will allocate taxable income which could be different in amount than the cash we distribute, they will be required to pay federal income taxes and, in some cases, state and local income taxes on their share of our taxable income even if they do not receive cash distributions from us. Unitholders may not receive cash distributions from us equal to their share of our taxable income or even the tax liability that results from that income.

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

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

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

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

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

Because we cannot match transferors and transferees of common units and because of other reasons, we will take 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 unitholders. It also could affect the timing of these tax benefits or the amount of gain from the sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to the tax returns of unitholders.

The sale or exchange of 50% or more of our capital or profits interests within a 12-month period will result in the termination of our partnership for federal income tax purposes.

We will be considered to have terminated our partnership for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital or profits within a 12-month period. Our 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. Our termination could also result in a deferral of depreciation deductions allowable in computing our taxable income. In the case of a unitholder who has adopted a taxable year other than a fiscal year ending December 31, the closing of our taxable year may also result in more than twelve months of our taxable income or loss being includable in such unitholder's taxable income for the year of termination. Our termination would cause us to be treated as a new partnership for tax purposes for which we must make new tax elections, and we could be subject to penalties if we were to fail to recognize and properly report on our tax return 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 its partnership makes a request for publicly traded partnership technical termination relief and such relief is granted by the IRS then, among other things, the partnership will only have to provide one Schedule K-1 to unitholders for the year notwithstanding two partnership tax years.

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, 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. For example, from time to time, the President and members of Congress propose and consider substantive changes to the existing federal income tax laws that affect publicly traded partnerships, including elimination of partnership tax treatment for publicly traded partnerships. Any modification to the federal income tax laws and interpretations thereof may or may not be retroactively applied and could make it more difficult or impossible for us to meet the requirements that must be satisfied in order for us to be treated as a partnership for federal income tax purposes.

On January 24, 2017, the U.S. Treasury Department and the IRS published final regulations regarding qualifying income under Section 7704(d)(1)(E) of the Code. We do not believe these regulations adversely affect our status as a partnership for federal income tax purposes.

We are unable to predict whether any of these changes, or other proposals, will ultimately be enacted. Any such changes could negatively impact the value of an investment in our common units. 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 income tax purposes, the minimum quarterly distribution and the target distribution levels will be adjusted to reflect the impact of that law on us.

We will adopt certain valuation methodologies and monthly conventions for 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.

Entity level taxes on income from our C corporation subsidiary will reduce cash available for distribution, and a unitholder's share of dividend and interest income from such subsidiary will constitute portfolio income that cannot be offset by the unitholder's share of other losses or deductions.

A portion of our taxable income is earned through a C corporation subsidiary. Such C corporation subsidiary is subject to federal income tax on its taxable income at the corporate tax rate, which is currently a maximum of 35%, and will likely pay state (and possibly local) income tax at varying rates, on its taxable income. Any such entity level taxes will reduce the cash available for distribution to our unitholders. Distributions from such C corporation subsidiary will generally be taxed again to unitholders as dividend income to the extent of current and accumulated earnings and profits of such subsidiary. Currently, the maximum federal income tax rate applicable to such dividend income which is allocable to individuals is 20% plus an unearned income Medicare tax of 3.8%. An individual unitholder's share of dividend and interest income from our C corporation subsidiary would constitute portfolio income that could not be offset by the unitholder's share of our other losses or deductions.

As a result of investing in our common units, you will likely be subject to state and local taxes and return filing or withholding requirements in jurisdictions where you do not live.

In addition to federal income taxes, you will likely be subject to other taxes such as state and local income taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we do business or own property. You will likely be required to file state and local tax returns and pay state and local income taxes in some or all of the various jurisdictions in which we do business or own property and you may be subject to penalties for failure to comply with those requirements. We own property or conduct business in a number of states, most of which currently impose a state income tax on individuals. Most of these states also impose an income tax on corporations and other entities. As we make acquisitions or expand our business, we may do business or own property in other states that impose an income tax. It is our unitholders' responsibility to file all federal, state, local, and foreign tax returns. Under the tax laws of some states where we will conduct business, we may be required to withhold a percentage from amounts to be distributed to a unitholder who is not a resident of that state. Our counsel has not rendered an opinion on the state, local, or foreign tax consequences of owning our common units.

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

We prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The U.S. Treasury Department and the IRS recently issued final Treasury Regulations pursuant to which a publicly traded partnership may use a similar monthly simplifying convention to allocate tax items among transferor and transferee unitholders although such tax items must be prorated on a daily basis. However, these Treasury Regulations do not specifically authorize the use of the proration method we have adopted. If the IRS were to successfully challenge our proration method, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

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

Because a unitholder whose units are loaned to a "short seller" to cover a short sale of units may be considered as having disposed of the loaned units, he may no longer be treated for tax purposes as a partner with respect to those units during the period of the loan to the short seller and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan to the short seller, any of our income, gain, loss or deduction with respect to those units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those units could be fully taxable as ordinary income. Our counsel has not rendered an opinion regarding the treatment of a unitholder where common units are loaned to a short seller to cover a short sale of common units; therefore, unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller are urged to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their units.

Compliance with and changes in tax law 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

We do not have any unresolved staff comments.

Item 2. Properties

A description of our properties is contained in “Item 1. Business.”

Title to Properties

Substantially all of our pipelines are constructed on rights-of-way granted by the apparent record owners of the property. Lands over which pipeline rights-of-way have been obtained may be subject to prior liens that have not been subordinated to the right-of-way grants. We have obtained, where necessary, easement agreements from public authorities and railroad companies to cross over or under, or to lay facilities in or along, watercourses, county roads, municipal streets, railroad properties and state highways, as applicable. In some cases, property on which our pipeline was built was purchased in fee. Our processing plants are located on land that we lease or own in fee.

We believe that we have satisfactory title to all of our rights-of-way and land assets. Title to these assets may be subject to encumbrances or defects. We believe that none of such encumbrances or defects should materially detract from the value of our assets or from our interest in these assets or should materially interfere with their use in the operation of the business.

Item 3. Legal Proceedings

Our operations are subject to a variety of risks and disputes normally incident to our business. As a result, at any given time we may be a defendant in various legal proceedings and litigation arising in the ordinary course of business, including litigation on disputes related to contracts, property use or damage and personal injury. We may continue to see claims brought by landowners, such as nuisance claims and other claims based on property rights. Except as otherwise set forth herein, we do not believe that any pending or threatened claim or dispute is material to our financial results on our operations or cash flows. We maintain insurance policies with insurers in amounts and with coverage and deductibles as our general partner believes are reasonable and prudent. However, we cannot assure you that this insurance will be adequate to protect us from all material expenses related to potential future claims for personal and property damage or that these levels of insurance will be available in the future at economical prices.

At times, our subsidiaries acquire pipeline easements and other property rights by exercising rights of eminent domain and common carrier. As a result, from time to time we or our subsidiaries are party to lawsuits under which a court will determine the value of pipeline easements or other property interests obtained by our subsidiaries by condemnation. Damage awards in these suits should reflect the value of the property interest acquired and the diminution in the value of the remaining property owned by the landowner. However, some landowners have alleged unique damage theories to inflate their damage claims or assert valuation methodologies that could result in damage awards in excess of the amounts anticipated. Although it is not possible to predict the ultimate outcomes of these matters, we do not expect that awards in these matters will have a material adverse impact on our consolidated results of operations, financial condition or cash flows.

We (or our subsidiaries) are defending lawsuits filed by owners of property located near processing facilities or compression facilities constructed by us as part of our systems. The suits generally allege that the facilities create a private nuisance and have damaged the value of surrounding property. Claims of this nature have arisen as a result of the industrial development of natural gas gathering, processing and treating facilities in urban and occupied rural areas.

In July 2013, the Board of Commissioners for the Southeast Louisiana Flood Protection Authority for New Orleans and surrounding areas filed a lawsuit against approximately 100 energy companies, seeking, among other relief, restoration of wetlands allegedly lost due to historic industry operations in those areas. The suit was filed in Louisiana state court in New Orleans, but was removed to the United States District Court for the Eastern District of Louisiana. The amount of damages is unspecified. Our subsidiary, EnLink LIG, LLC, is one of the named defendants as the owner of pipelines in the area. On February 13, 2015, the court granted defendants’ joint motion to dismiss and dismissed the plaintiff’s claims with prejudice. Plaintiffs have appealed the matter to the United States Court of Appeals for the Fifth Circuit. We intend to continue vigorously defending the case. The success of the plaintiffs' appeal as well as our costs and legal exposure, if any, related to the lawsuit are not currently determinable.

We own and operate a high-pressure pipeline and underground natural gas and NGL storage reservoirs and associated facilities near Bayou Corne, Louisiana. In August 2012, a large sinkhole formed in the vicinity of this pipeline and underground storage reservoirs. We are seeking to recover our losses from responsible parties. We have sued Texas Brine Company, the operator of a failed cavern in the area and its insurers, seeking recovery for these losses in in the 23rd Judicial Court, Assumption Parish, Louisiana. We have also sued Occidental Chemical Company and Legacy Vulcan Corp. f/k/a Vulcan Materials Company, two Chlor-Alkali plant operators that participated in Texas Brine's operational decisions regarding mining the failed cavern. We also filed a claim with our insurers, which our insurers denied. We have filed a claim for defense and indemnity with our insurers. In August 2014, we received a partial settlement from Texas Brine's insurers with respect to the Texas Brine claims in the amount of $6.1 million, but additional claims remain outstanding. We cannot give assurance that we will be able to fully recover our losses through insurance recovery or claims against responsible parties.

In June 2014, a group of landowners in Assumption Parish, Louisiana added our subsidiary, EnLink Processing Services, LLC, as a defendant in a pending lawsuit they had filed against Texas Brine, Occidental Chemical Corporation, and Vulcan Materials Company relating to claims arising from the Bayou Corne sinkhole. The suit is pending in the 23rd Judicial Court, Assumption Parish, Louisiana. Although plaintiffs' claims against the other defendants had been pending since October 2012, plaintiffs alleged in June 2014 and continue to allege that EnLink Processing Services, LLC's negligence also contributed to the formation of the sinkhole. The amount of damages is unspecified. The validity of the causes of action, as well as our costs and legal exposure, if any, related to the lawsuit are not currently determinable. We intend to vigorously defend the case. We have also filed a claim for defense and indemnity with our insurers.

Item 4. Mine Safety Disclosures

Not applicable.

PART II

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

Our common units are listed on the NYSE under the symbol "ENLK." On February 8, 2017, there were approximately 32,431 record holders and beneficial owners (held in street name) of our common units. For equity compensation plan information, see discussion under "Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters—Equity Compensation Plan Information."

The following table shows the high and low sales prices per common unit, as reported by the NYSE and cash distributions declared per common unit for the periods indicated:

	Range		Cash Distribution
	High	Low	Declared Per Unit
2016:			
Quarter Ended December 31	$ 18.62	$ 16.09	$ 0.390
Quarter Ended September 30	19.03	16.34	0.390
Quarter Ended June 30	17.06	10.74	0.390
Quarter Ended March 31	16.74	7.71	0.390
2015:			
Quarter Ended December 31	$ 18.53	$ 12.86	$ 0.390
Quarter Ended September 30	22.37	14.99	0.390
Quarter Ended June 30	25.91	21.97	0.385
Quarter Ended March 31	30.01	24.50	0.380

Unless restricted by the terms of our credit facility, within 45 days after the end of each quarter, we will distribute all of our available cash, as defined in our partnership agreement, to common unitholders of record on the applicable record date. Our available cash consists generally of all cash on hand at the end of the fiscal quarter plus all cash on hand on the date of determination resulting from working capital borrowings made after the end of the fiscal quarter, less reserves that our general partner determines are necessary to:

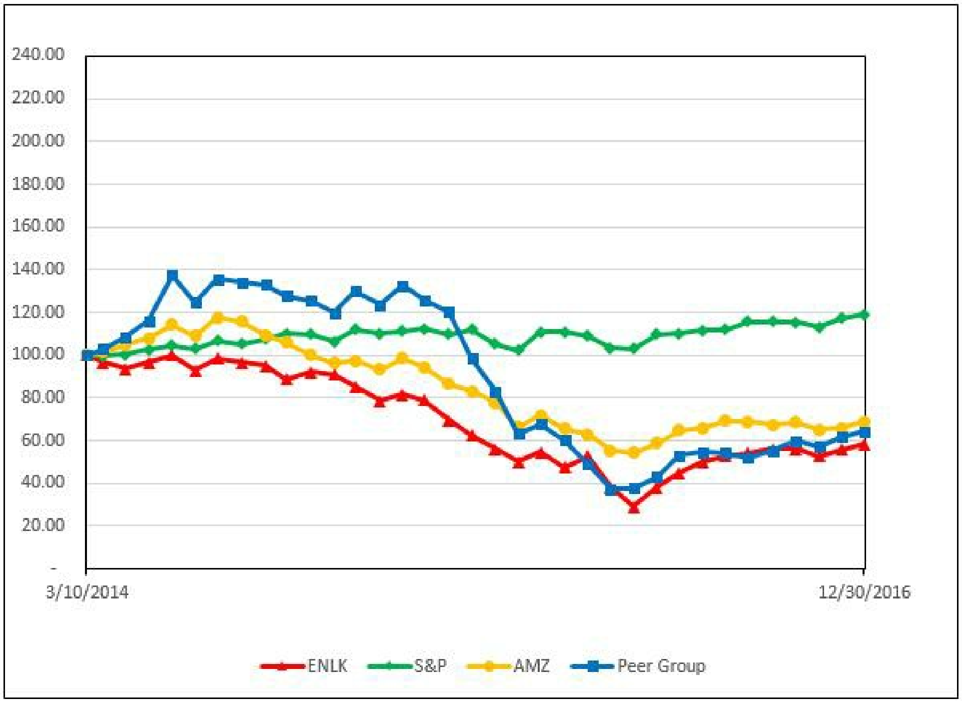
- provide for the proper conduct of our business;
- comply with applicable law, our debt instruments or other agreements; and
- provide funds for distributions to our unitholders and to our general partner for any one or more of the next four quarters.

Under our existing credit facility, we may be limited from making certain distributions if an event of default exists. Please read "Item 8. Financial Statements and Supplementary Data—Note 6" for additional information concerning our credit facility.

Our general partner has broad discretion to establish cash reserves that it determines are necessary or appropriate to properly conduct our business. These can include cash reserves for future capital and maintenance expenditures, reserves to stabilize distributions of cash to the unitholders and our general partner, reserves to reduce debt or, as necessary, reserves to comply with the terms of any of our agreements or obligations. Our distributions are made to our general partner based on its ownership interest with the remaining interest to unitholders, subject to the payment of incentive distributions to our general partner if certain target cash distribution levels to common unitholders are achieved. Incentive distributions to our general partner increase to 13.0%, 23.0% and 48.0% based on incremental distribution thresholds as set forth in our partnership agreement.

Performance Graph

The following graph sets forth the cumulative total stockholder return for our common units, the Standard & Poor's 500 Stock Index, Alerian MLP Index and a peer group of publicly traded partners of publicly traded limited partnerships in the Midstream natural gas, natural gas liquids, propane, and pipeline industries for the year ended December 31, 2016. The chart assumes that $100 was invested on March 10, 2014, with distributions reinvested. The peer group includes MarkWest Energy Partners, L.P., Energy Transfer Equity, L.P., Targa Resources, Inc. and Western Gas Equity Partners, L.P.



Item 6. Selected Financial Data

The historical financial statements included in this report reflect (1) for periods prior to March 7, 2014, the assets, liabilities and operations of EnLink Midstream Holdings, LP Predecessor (the "Predecessor"), the predecessor to EnLink Midstream Holdings, LP ("Midstream Holdings"), which is the historical predecessor of EnLink Midstream Partners, LP (the "Partnership") and (2) for periods on or after March 7, 2014, the results of operations of EnLink Midstream Partners, LP after giving effect to the Business Combination discussed under "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Devon Energy Transaction and EMH Drop Downs" below. The Predecessor was comprised of all of the U.S. midstream assets and operations of Devon Energy Corporation ("Devon") prior to the Business Combination, including its 38.75% interest in Gulf Coast Fractionators ("GCF"). However, in connection with the Business Combination, only the Predecessor's systems serving the Barnett, Cana-Woodford and Arkoma-Woodford Shales in Texas and Oklahoma, as well as the economic burdens and benefits of the 38.75% interest in GCF, were contributed to Midstream Holdings, effective as of March 7, 2014.

The following table presents our selected historical financial and operating data for the periods indicated. Financial and operating data for the years ended December 31, 2016, 2015 and 2014 reflect acquisitions and dispositions for periods subsequent to the applicable transaction date. The selected historical financial data should be read together with "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and the consolidated financial statements and accompanying notes in "Item 8. Financial Statements and Supplementary Data."

	EnLink Midstream Partners, LP Year Ended December 31,				
	2016	2015	2014 (4)	2013 (4)	2012 (4)
	(In millions, except per unit data)				
Revenues:					
Product sales	$ 3,008.9	$ 3,253.7	$ 2,159.3	$ 179.4	$ 153.9
Product sales - related parties	134.3	119.4	505.6	2,116.5	1,753.9
Midstream services	467.2	451.0	253.4	—	—
Midstream services - related parties	653.1	618.6	567.4	—	—
Gain (loss) on derivatives	(11.1)	9.4	22.1	—	—
Total revenue	4,252.4	4,452.1	3,507.8	2,295.9	1,907.8
Operating costs and expenses:					
Cost of sales (1)	3,015.5	3,245.3	2,494.5	1,736.3	1,428.1
Operating expenses (2)	398.5	419.9	283.6	156.2	149.9
General and administrative (3)	119.3	132.4	94.5	45.1	41.7
(Gain) loss on disposition of assets	13.2	1.2	(0.1)	—	—
Depreciation and amortization	503.9	387.3	284.3	187.0	145.4
Impairments	566.3	1,563.4	—	—	16.4
Gain on litigation settlement	—	—	(6.1)	—	—
Total operating costs and expenses	4,616.7	5,749.5	3,150.7	2,124.6	1,781.5
Operating income (loss)	(364.3)	(1,297.4)	357.1	171.3	126.3
Other income (expense):					
Interest expense, net of interest income	(188.1)	(102.5)	(47.4)	—	—
Income from unconsolidated affiliates	(19.9)	20.4	18.9	14.8	2.0
Gain on extinguishment of debt	—	—	3.2	—	—
Other income (expense)	0.3	0.8	(0.5)	—	—
Total other income (expense)	(207.7)	(81.3)	(25.8)	14.8	2.0
Income (loss) from continuing operations before non-controlling interest and income taxes	(572.0)	(1,378.7)	331.3	186.1	128.3
Income tax (provision) benefit	(1.3)	0.5	(22.0)	(67.0)	(46.2)
Net income (loss) from continuing operations	(573.3)	(1,378.2)	309.3	119.1	82.1
Discontinued operations:					
Income (loss) from discontinued operations, net of tax	—	—	1.0	(2.3)	(5.2)
Income from discontinued operations attributable to non-controlling interest, net of tax	—	—	—	(1.3)	(1.1)
Discontinued operations, net of tax	—	—	1.0	(3.6)	(6.3)
Net income (loss)	(573.3)	(1,378.2)	310.3	115.5	75.8
Less: Net loss from continuing operations attributable to the non-controlling interest	(8.1)	(0.4)	(0.2)	—	—
Net income (loss) attributable to EnLink Midstream Partners, LP	$ (565.2)	$ (1,377.8)	$ 310.5	$ 115.5	$ 75.8
Predecessor interest in net income	$ —	$ —	$ 35.5	$ —	$ —
General partner interest in net income	$ 39.5	$ 58.0	$ 138.3	$ —	$ —
Limited partners' interest in net income (loss) attributable to EnLink Midstream Partners, LP	$ (662.1)	$ (1,405.2)	$ 136.7	$ —	$ —
Class C partners' interest in net income (loss) attributable to EnLink Midstream Partners, LP	$ (12.5)	$ (30.6)	$ —	$ —	$ —
Preferred interest in net income attributable to EnLink Midstream Partners, LP	$ 69.9	$ —	$ —	$ —	$ —
Net income (loss) attributable to EnLink Midstream Partners, LP per limited partners' unit:					
Basic and diluted common unit	$ (1.99)	$ (4.66)	$ 0.59	$ —	$ —
Distributions declared per limited partner unit	$ 1.560	$ 1.545	$ 1.470	$ —	$ —

(1) Includes related party cost of sales of $150.1 million, $141.3 million, $354.3 million, $1,588.2 million, and $1,310.3 million for the years ended December 31, 2016, 2015, 2014, 2013 and 2012, respectively.

(2) Includes related party operating expense of $0.5 million, $0.5 million, $5.9 million, $36.2 million, and $33.8 million for the years ended December 31, 2016, 2015, 2014, 2013 and 2012, respectively.

(3) Includes related party general and administrative expenses of $0.0 million, $0.2 million, $11.6 million, $45.1 million, and $41.7 million for the years ended December 31, 2016, 2015, 2014, 2013 and 2012, respectively.

(4) Prior to March 7, 2014, our financial results only included the assets, liabilities and operations of our Predecessor. Beginning on March 7, 2014, our financial results also consolidate the assets, liabilities and operations of the legacy business of the Partnership prior to giving effect to the Business Combination. In connection with the Business Combination, we entered into new agreements with Devon that were effective on March 1, 2014 pursuant to which we provide services to Devon under fixed-fee arrangements in which we do not take title to the natural gas gathered or processed or the NGLs we fractionate. Prior to the effectiveness of these agreements, the Predecessor provided services to Devon under a percent-of-proceeds arrangement in which it took title to the natural gas it gathered and processed and the NGLs it fractionated.

	EnLink Midstream Partners, LP Year Ended December 31,				
	2016	2015	2014	2013	2012
	(In millions, except per unit data)				
Balance Sheet Data (end of period):					
Property and equipment, net	$6,256.7	$5,666.8	$5,042.8	$1,768.1	$1,739.4
Total assets	9,153.4	8,092.8	8,702.0	2,309.8	2,535.2
Long-term debt (including current maturities)	3,268.0	3,066.8	2,022.5	—	—
Partners' equity including non-controlling interest	4,640.4	4,434.5	6,025.9	1,783.7	2,002.0

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

Please read the following discussion of our financial condition and results of operations in conjunction with the financial statements and notes thereto included elsewhere in this report. For more detailed information regarding the basis of presentation for the following information, please read the notes to the financial statements included in this report.

The historical financial statements included in this report reflect (1) for periods prior to March 7, 2014, the assets, liabilities and operations of EnLink Midstream Holdings, LP Predecessor (the "Predecessor"), the predecessor to EnLink Midstream Holdings, LP ("Midstream Holdings"), which is the historical predecessor of EnLink Midstream Partners, LP and (2) for periods on or after March 7, 2014, the results of operations of EnLink Midstream Partners, LP after giving effect to the Business Combination discussed under "Devon Energy Transaction" below . The Predecessor was comprised of all of the U.S. midstream assets and operations of Devon Energy Corporation ("Devon") prior to the Business Combination, including its 38.75% interest in Gulf Coast Fractionators ("GCF"). However, in connection with the Business Combination, only the Predecessor's systems serving the Barnett, Cana-Woodford and Arkoma-Woodford Shales in Texas and Oklahoma, as well as the economic burdens and benefits of the 38.75% interest in GCF, were contributed to Midstream Holdings, effective as of March 7, 2014.

All references in this section to the "Partnership", as well as the terms "our," "we," "us" and "its" (1) for periods prior to March 7, 2014 refer to the Predecessor and (2) for periods on or after March 7, 2014 refer to EnLink Midstream Partners, LP, together with its consolidated subsidiaries including EnLink Midstream Operating, LP (the "Operating Partnership") and EnLink Oklahoma Gas Processing, LP ("EnLink Oklahoma T.O.").EnLink Oklahoma T.O. is sometimes used herein to refer to EnLink Oklahoma Gas Processing, LP itself or EnLink Oklahoma Gas Processing, LP, together with its consolidated subsidiaries.

Overview

We are a Delaware limited partnership formed on July 12, 2002. We primarily focus on providing midstream energy services, including gathering, processing, transmission, fractionation, storage, condensate stabilization, brine services and marketing to producers of natural gas, NGLs, crude oil and condensate. Our midstream energy asset network includes approximately 11,000 miles of pipelines, 20 natural gas processing plants, 7 fractionators, barge and rail terminals, product storage facilities, purchasing and marketing capabilities, brine disposal wells, a crude oil trucking fleet, and equity investments in certain private midstream companies. We manage and report our activities primarily according to the nature of activity and geography. We have five reportable segments, which include the:

- *Texas Segment.* The Texas segment includes our natural gas gathering, processing and transmission activities in north Texas and the Permian Basin in west Texas;

- *Oklahoma Segment*. The Oklahoma segment includes our natural gas gathering, processing and transmission activities in Cana-Woodford, Arkoma-Woodford, Northern Oklahoma Woodford, Sooner Trend Anadarko Basin Canadian and Kingfisher Counties ("STACK"), South Central Oklahoma Oil Province ("SCOOP") and Central Northern Oklahoma Woodford ("CNOW") Shale areas;

- *Louisiana Segment*. The Louisiana segment includes our natural gas pipelines, natural gas processing plants, storage facilities and NGL assets located in Louisiana;

- *Crude and Condensate Segment*. The Crude and Condensate segment includes our Ohio River Valley ("ORV") crude oil, condensate and brine disposal activities in the Utica and Marcellus Shales, our condensate stabilization and natural gas compression stations in the Utica and Marcellus Shales, our crude oil operations in the Permian Basin and our crude oil activities associated with the Victoria Express Pipeline and related truck terminal and storage assets ("VEX") located in the Eagle Ford Shale; and

- *Corporate Segment*. The Corporate segment includes our unconsolidated affiliate investments in Howard Energy Partners ("HEP"), our ownership in the Cedar Cove JV in Oklahoma and our contractual right to the economic burdens and benefits associated with Devon's ownership interest in GCF in south Texas and our general partnership property and expenses.

We manage our operations by focusing on gross operating margin because our business is generally to gather, process, transport or market natural gas, NGLs, crude oil and condensate using our assets for a fee. We earn our fees through various contractual arrangements, which include stated fixed-fee contract arrangements or arrangements where we purchase and resell commodities in connection with providing the related service and earn a net margin as our fee. While our transactions vary in form, the essential element of each transaction is the use of our assets to transport a product or provide a processed product to an end-user at the tailgate of the plant, barge terminal or pipeline. We define gross operating margin as operating revenue minus cost of sales. Gross operating margin is a non-GAAP financial measure and is explained in greater detail under "Non-GAAP Financial Measures" below. Approximately 97% of our gross operating margin was derived from fee-based services with no direct commodity exposure for the year ended December 31, 2016. We reflect revenue as "Product sales" and "Midstream services" on the consolidated statements of operations.

Our gross operating margins are determined primarily by the volumes of:

- natural gas gathered, transported, purchased and sold through our pipeline systems;
- natural gas processed at our processing facilities;
- NGLs handled at our fractionation facilities;
- crude oil and condensate handled at our crude terminals;
- crude oil and condensate gathered, transported, purchased and sold;
- brine disposed; and
- condensate stabilized.

We generate revenues from eight primary sources:

- gathering and transporting natural gas and NGLs on the pipeline systems we own;
- processing natural gas at our processing plants;
- fractionating and marketing recovered NGLs;
- providing compression services;
- providing crude oil and condensate gathering, transportation and terminal services;
- providing condensate stabilization services;
- providing brine disposal services; and
- providing gas, crude, and NGL storage.

We typically gather or transport gas owned by others through our facilities for a fee. We also buy natural gas from producers, plants or shippers at either a fixed discount to a market index or a percentage of the market index, and then transport and resell the natural gas at the same market index. The fixed discount difference to a market index represents the fee for using our assets. We attempt to execute substantially all purchases and sales concurrently, or we enter into a future delivery obligation, thereby establishing the basis for the fee we will receive for each natural gas transaction. Our gathering and transportation fee related to a percentage of the index price can be adversely affected by declines in the price of natural gas. We are also party to certain long-term gas sales commitments that we satisfy through supplies purchased under long-term gas purchase agreements. When we enter into those arrangements, our sales obligations generally match our purchase obligations. However, over time, the supplies that we have under contract may decline due to reduced drilling or other causes, and we may be required to satisfy the sales obligations by buying additional gas at prices that may exceed the prices received under the sales commitments. In our purchase/sale transactions, the resale price is generally based on the same index at which the gas was purchased.

On occasion, we have entered into certain purchase/sale transactions in which the purchase price is based on a production-area index and the sales price is based on a market-area index, and we capture the difference in the indices (also referred to as "basis spread"), less the transportation expenses from the two areas, as our fee. Changes in the basis spread can increase or decrease our margins or potentially result in losses. For example, we are a party to one contract associated with our north Texas operations with a term to 2019 to supply approximately 150,000 MMBtu/d of gas. We buy gas for this contract on several different production-area indices and sell the gas into a different market area index. We realize a cash loss on the delivery of gas under this contract each month based on current prices. The fair value of this performance obligation was recorded based on forecasted discounted cash obligations in excess of market prices under this gas delivery contract. As of December 31, 2016, the balance sheet reflects a liability of $44.8 million related to this performance obligation. Narrower basis spreads in recent periods have increased the losses on this contract, and greater losses on this contract could occur in future periods if these conditions persist or become worse.

We typically transport and fractionate or store NGLs owned by others for a fee based on the volume of NGLs transported and fractionated or stored. We also buy mixed NGLs from our suppliers at a fixed discount to market indices for the component NGLs with a deduction for our fractionation fee. We subsequently sell the fractionated NGL products based on the same index-based prices. The operating results of our NGL fractionation business are dependent upon the volume of mixed NGLs fractionated and the level of fractionation fees charged. With our fractionation business, we also have the opportunity for product upgrades for each of the discrete NGL products. The fees we earn on the product upgrade from this fractionation business are higher during periods with higher liquids prices.

We typically gather or transport crude oil and condensate owned by others by rail, truck, pipeline and barge facilities for a fee. We also buy crude oil and condensate from a producer at a fixed discount to a market index and then transport and resell the crude oil and condensate at the same market index. We execute substantially all purchases and sales concurrently, thereby establishing the fee we will receive for each crude oil and condensate transaction.

We realize gross operating margins from our processing services primarily through different contractual arrangements: processing margins (“margin”), percentage of liquids (“POL”), percentage of proceeds (“POP”) or fixed-fee based. Under margin contract arrangements, our gross operating margins are higher during periods of high liquid prices relative to natural gas prices. Gross operating margin results under POL contracts are impacted only by the value of the liquids produced with margins higher during periods of higher liquids prices. Gross operating margin results under POP contracts are impacted only by the value of the natural gas and liquids produced with margins higher during periods of higher natural gas and liquids prices. Under fixed-fee based contracts, our gross operating margins are driven by throughput volume. See “Item 7A. Quantitative and Qualitative Disclosures about Market Risk—Commodity Price Risk.”

Operating expenses are costs directly associated with the operations of a particular asset. Among the most significant of these costs are those associated with direct labor and supervision, property insurance, property taxes, repair and maintenance expenses, contract services and utilities. These costs are normally fairly stable across broad volume ranges and therefore do not normally increase or decrease significantly in the short term with increases or decreases in the volume of gas, liquids, crude oil and condensate moved through or by the asset.

Our general and administrative expenses are dictated by the terms of our partnership agreement. These expenses include the costs of employee, officer and director compensation and benefits properly allocable to us, fees, services and other transaction costs related to acquisitions, and all other expenses necessary or appropriate to the conduct of business and allocable to us. Our partnership agreement provides that our general partner determines the expenses that are allocable to us in any reasonable manner determined by our general partner at its sole discretion.

Recent Growth Developments

Acquisitions and Expansion

EnLink Oklahoma T.O. Acquisition and Expansion. On January 7, 2016, we and ENLC acquired an 84% and 16% interest, respectively, in EnLink Oklahoma T.O. for approximately $1.4 billion. The first installment of $1.02 billion for the acquisition was paid at closing. The second installment of $250.0 million was paid on January 6, 2017, and the final installment of $250.0 million is due no later than January 7, 2018. The installment payables are valued net of discount within the total purchase price.

The first installment consisted of approximately $1.02 billion and was funded by (a) approximately $783.6 million in cash paid by us, the majority of which was derived from the proceeds from the issuance of Preferred Units (as defined under “Issuance of Preferred Units” below), and (b) 15,564,009 common units representing limited liability company interests in ENLC issued directly by ENLC and approximately $22.2 million in cash paid by ENLC.

The EnLink Oklahoma T.O. assets serve gathering and processing needs in the growing STACK and CNOW plays in Oklahoma and are supported by long-term, fixed-fee contracts with acreage dedications that, at the time of acquisition, had a weighted-average term of approximately 15 years. The EnLink Oklahoma T.O. assets are strategically located in the core areas of the STACK and CNOW plays and include:

- *Chisholm Plant.* The Chisholm Plant, which serves the STACK play, is a cryogenic gas processing plant with a capacity of 120 MMcf/d. The plant is connected to a 350-mile, low- and high-pressure gathering system with compression facilities, including gathering pipelines and compression facilities completed by us during 2016.

  During 2016, we commenced construction on a new cryogenic gas processing plant, referred to as Chisholm II, that will provide an additional 200 MMcf/d of processing capacity and will be tied to new and existing pipelines in the STACK and SCOOP play. Chisholm II is scheduled to be completed during the first quarter of 2017. The new capacity is supported by long-term contracts.

  Additionally, we expect to commence construction on Chisholm III in April 2017. Chisholm III will provide an additional 200 MMcf/d of processing capacity and will be tied to new and existing pipelines in the STACK and SCOOP play. Construction is scheduled to be completed by the fourth quarter of 2017.

- *Battle Ridge Plant.* The Battle Ridge Plant is a cryogenic gas processing plant located in the CNOW play with a current capacity of 75 MMcf/d. The plant is connected to a 250-mile, low and high-pressure gathering system with compression facilities.

- *Connecting Pipeline.* A 42-mile, 16-inch high-pressure header pipeline with a total capacity of 150 MMcf/d was constructed to connect the Chisolm and Battle Ridge systems. The pipeline went into service in March 2016 and provides customers with additional operational flexibility.

Organic Growth

Greater Chickadee Crude Oil Gathering System. We have a new crude oil gathering system in Upton and Midland counties, Texas in the Permian Basin that we refer to as “Greater Chickadee.” Greater Chickadee includes approximately 185 miles of high- and low-pressure pipelines that will transport crude oil volumes to several major market outlets and other key hub centers in the Midland, Texas area. Greater Chickadee also includes the construction of 50,000 Bbls of crude oil storage and a truck injection station to maximize shipping and delivery options for our producer customers. The initial phase of our Greater Chickadee transportation service began in November 2016. Additional construction is ongoing, and we expect full service capabilities in the first quarter of 2017.

Cedar Cove Joint Venture. On November 9, 2016, we formed the Cedar Cove JV with Kinder Morgan, Inc., consisting of gathering and compression assets in Blaine County, Oklahoma, located in the heart of the STACK play. The gathering system has a capacity of 25 MMcf/d with over 50,000 gross acres of dedications and ties into our existing Oklahoma assets. All gas gathered by the Cedar Cove JV will be processed at our central Oklahoma processing system. We committed to contribute $40.0 million in cash in exchange for 30% ownership of the Cedar Cove JV, and as of December 31, 2016, we have contributed $28.8 million. Thereafter, we and Kinder Morgan, Inc. will contribute additional capital in proportion to our respective ownership interests to fund operations.

Delaware Basin Joint Venture. On August 1, 2016, we formed the Delaware Basin JV with NGP to operate and expand our natural gas, natural gas liquids and crude oil midstream assets in the liquids-rich Delaware Basin. The Delaware Basin JV is owned 50.1% by us and 49.9% by NGP. We contributed approximately $221.0 million of existing assets, net of depreciation, to the Delaware Basin JV and committed an additional $285.0 million in capital to fund potential future development projects and potential acquisitions. NGP committed an aggregate of approximately $400.0 million of capital, including an initial contribution of $114.3 million, which the Delaware Basin JV distributed to us at the formation of the joint venture to reimburse us for capital spent to the date of formation on existing assets and ongoing projects. In addition to the initial contributions, we and NGP contributed $30.2 million and $30.1 million, respectively, to the Delaware Basin JV for the year ended December 31, 2016. As part of this agreement, NGP granted us call rights beginning in 2021 to acquire increasing portions of NGP’s interest in the joint venture at a price based upon a predetermined valuation methodology.

Lobo II Natural Gas Gathering and Processing Facility. In October 2016, we completed construction of a new cryogenic gas processing plant located in the Delaware Basin (our "Lobo II plant") with initial capacity of 60 MMcf/d. The Lobo II expansion also included the construction of a 75-mile gathering system located in Texas and New Mexico. Construction on the Texas portion of the gathering system was completed in October 2016, and the remaining New Mexico pipeline was completed in the first quarter of 2017. The Lobo II facilities are part of the Delaware Basin JV.

Riptide Processing Plant. In April 2016, we completed construction of the Riptide processing plant in the Permian Basin. The plant provides 100 MMcf/d of processing capacity and is tied to approximately 50 miles of new gathering pipeline, all of which is connected to our Midland Energy Gathering Area assets (the "MEGA system").

Ascension Joint Venture. We have formed a 50/50 joint venture named Ascension Pipeline Company, LLC (the "Ascension JV") with a subsidiary of Marathon Petroleum Corporation ("Marathon Petroleum") to build a new 30-mile NGL pipeline connecting our existing Riverside fractionation and terminal complex to Marathon Petroleum's Garyville refinery located on the Mississippi River. We commenced construction of the pipeline during 2016 and will operate the pipeline upon completion, which is currently estimated to be during the second quarter of 2017. This bolt-on project to our Cajun-Sibon NGL system is supported by long-term, fee-based contracts with Marathon Petroleum.

Sale of Non-Core Assets

In December 2016, we entered into an agreement to sell our ownership interest in HEP for approximately $193.1 million, subject to customary closing conditions, including regulatory approvals. We expect the transaction to close in the first quarter of 2017. For the year ended December 31, 2016, we recorded an impairment loss of $20.1 million to reduce the carrying value of our investment to the expected sales price.

In December 2016, we sold the North Texas Pipeline (the "NTPL"), a 140-mile natural gas transportation pipeline, for $84.6 million. We maintain capacity on the NTPL at competitive rates and at levels sufficient to support current and expected operations. We recorded a loss related to the sale of $13.4 million.

Issuance of Senior Notes

On July 14, 2016, we issued $500.0 million in aggregate principal amount of our 4.850% senior notes due 2026 (the "2026 Notes") at a price to the public of 99.859% of their face value. The 2026 Notes mature on July 15, 2026. Interest payments on the 2026 Notes are payable on January 15 and July 15 of each year, beginning January 15, 2017. Net proceeds of approximately $495.7 million were used to repay outstanding borrowings under our revolving credit facility and for general partnership purposes.

Issuance of Common Units

Equity Distribution Agreement. In November 2014, we entered into an equity distribution agreement (the "BMO EDA") with BMO Capital Markets Corp. and certain other sales agents to sell up to $350.0 million in aggregate gross sales of our common units from time to time through an "at the market" equity offering program. We may also sell common units to any sales agent as principal for the sales agent's own account at a price agreed upon at the time of sale. We have no obligation to sell any of the common units under the BMO EDA and may at any time suspend solicitation and offers under the BMO EDA.

For the year ended December 31, 2016, we sold an aggregate of 10.0 million common units under the BMO EDA, generating proceeds of approximately $167.5 million (net of approximately $1.7 million of commissions). We used the net proceeds for general partnership purposes. As of December 31, 2016, approximately $147.8 million remains available to be issued under the BMO EDA.

Issuance of Preferred Units

On January 7, 2016, we issued an aggregate of 50,000,000 Series B Cumulative Convertible Preferred Units representing limited partner interests in our partnership (the "Preferred Units") to Enfield Holdings, L.P. ("Enfield") in a private placement (the "Private Placement") for a cash purchase price of $15.00 per Preferred Unit (the "Issue Price"), resulting in net proceeds of approximately $724.1 million after fees and deductions. Proceeds from the Private Placement were used to fund the EnLink Oklahoma T.O. acquisition.

The Preferred Units are convertible into our common units on a one-for-one basis, subject to certain adjustments, at any time after the record date for the quarter ending June 30, 2017 (a) in full, at our option, if the volume weighted average price of a common unit over the 30-trading day period ending two trading days prior to the conversion date (the "Conversion VWAP") is greater than 150% of the Issue Price or (b) in full or in part, at Enfield's option. In addition, upon certain events involving a change of control of our general partner or the managing member of ENLC, all of the Preferred Units will automatically convert into a number of common units equal to the greater of (i) the number of common units into which the Preferred Units would then convert and (ii) the number of Preferred Units to be converted multiplied by an amount equal to (x) 140% of the Issue Price divided by (y) the Conversion VWAP.

Enfield receives quarterly distributions, subject to certain adjustments, equal to (x) during the quarter ending March 31, 2016 through the quarter ending June 30, 2017, an annual rate of 8.5% on the Issue Price payable in-kind in the form of additional Preferred Units and (y) thereafter, at an annual rate of 7.5% on the Issue Price payable in cash (the "Cash Distribution Component") plus an in-kind distribution equal to the greater of (A) an annual rate of 1.0% of the Issue Price and (B) an amount equal to (i) the excess, if any, of the distribution that would have been payable had the Preferred Units converted into common units over the Cash Distribution Component, divided by (ii) the Issue Price. Distributions on the Preferred Units for the three months ended March 31, 2016, June 30, 2016 and September 30,2016, were paid-in kind through the issuance of 992,445, 1,083,589, and 1,106,616 Preferred Units on May 12, 2016, August 11, 2016, and November 10, 2016, respectively. A distribution on the Preferred Units was declared for the three months ended December 31, 2016, which will result in the issuance of 1,130,131 additional Preferred Units on February 13, 2016. Income was allocated to the Preferred Units in an amount equal to the quarterly distribution with respect to the period earned. For the year ended December 31, 2016, $69.9 million of income was allocated to the Preferred Units, respectively.

Acquisitions in 2014 and 2015:

- On November 1, 2014, we acquired, from affiliates of Chevron Corporation, Gulf Coast natural gas pipeline assets predominantly located in southern Louisiana, together with 100% of the voting interests in certain entities, for approximately $231.5 million.

- In 2014, we completed the drop down of certain equity interests in EnLink Appalachian Compression, LLC (formerly, E2 Appalachian Compression, LLC) and E2 Energy Services, LLC (collectively, "E2") from ENLC.

- On January 31, 2015, we acquired 100% of the voting equity interests of LPC Crude Oil Marketing LLC ("LPC"), which has crude oil gathering, transportation and marketing operations in the Permian Basin, for approximately $108.1 million.

- On March 16, 2015, we acquired 100% of the voting equity interests in Coronado Midstream Holdings LLC ("Coronado"), which owns natural gas gathering and processing facilities in the Permian Basin, for approximately $600.3 million.

- On October 1, 2015, we acquired 100% of the voting equity interests in a subsidiary of Matador Resources Company ("Matador"), which has gathering and processing assets operations in the Delaware Basin, for approximately $141.3 million.

- Prior to November 2015, we co-owned the Deadwood natural gas processing plant with a subsidiary of Apache Corporation ("Apache"). On November 16, 2015, we acquired Apache's 50% ownership interest in the Deadwood natural gas processing facility for approximately $40.1 million. We now own 100% of the Deadwood processing plant.

- In 2015, we completed the EMH Drop Downs and a drop down transaction to acquire VEX from Devon.

Devon Energy Transaction and EMH Drop Downs

On March 7, 2014, we consummated the transactions contemplated by the Contribution Agreement, dated as of October 21, 2013, among us, the Operating Partnership, Devon, Devon Gas Corporation, Devon Gas Services, L.P. ("Gas Services") and Southwestern Gas Pipeline, Inc. ("Southwestern Gas" and, together with Gas Services, the

"Contributors") pursuant to which the Contributors contributed (the "Contribution") to the Operating Partnership a 50% limited partner interest in Midstream Holdings and all of the outstanding equity interests in EnLink Midstream Holdings GP, LLC, the general partner of Midstream Holdings ("Midstream Holdings GP"), in exchange for the issuance by the Partnership of 120,542,441 units representing limited partnership interests in us.

Also on March 7, 2014, EnLink Midstream, Inc. ("EMI") and Devon consummated the transactions contemplated by the Merger Agreement, dated as of October 21, 2013, among the EMI, Devon, ENLC, Acacia Natural Gas Corp I, Inc., formerly a wholly-owned subsidiary of Devon, and certain other wholly-owned subsidiaries of Devon pursuant to which EMI and Acacia each became wholly-owned subsidiaries of ENLC (collectively, the "Mergers" and together with the Contribution, the "Business Combination"). Upon completion of the merger with Acacia, ENLC indirectly owned the remaining 50% limited partner interest in Midstream Holdings.

On February 17, 2015, we acquired a 25% limited partner interest in Midstream Holdings (the "February 2015 Transferred Interests") from Acacia, a wholly-owned subsidiary of ENLC, in a drop down transaction (the "February 2015 EMH Drop Down"). As consideration for the February 2015 Transferred Interests, we issued 31.6 million units in our partnership to Acacia. On May 27, 2015, we acquired the remaining 25% interest in Midstream Holdings (the "May 2015 Transferred Interests" and, together with the February 2015 Transferred Interests, the "2015 Transferred Interests") from Acacia in a drop down transaction (the "May 2015 EMH Drop Down" and, together with the February 2015 EMH Drop Down, the "EMH Drop Downs"). As consideration for the May 2015 Transferred Interests, we issued 36.6 million units in our partnership to Acacia. After giving effect to the EMH Drop-Downs, we own 100% of Midstream Holdings.

As of December 31, 2016, Devon held approximately 23.8% of our outstanding limited partner interests. Public common unitholders and preferred unitholders held approximately 40.1% and 13.4% of the outstanding limited partner interests, respectively. ENLC indirectly held approximately 22.3% of the outstanding limited partner interests and an approximate 0.4% general partner interest as of December 31, 2016.

Non-GAAP Financial Measures

We include the following non-GAAP financial measures in this report: Adjusted earnings before interest, taxes, depreciation and amortization, or adjusted EBITDA, distributable cash flow and gross operating margin.

Adjusted EBITDA

We define adjusted EBITDA as net income (loss) from continuing operations plus interest expense, provision for income taxes, depreciation and amortization expense, impairments, unit-based compensation, (gain) loss on non-cash derivatives, (gain) loss on disposition of assets, successful transaction costs, accretion expense associated with asset retirement obligations, reimbursed employee costs, non-cash rent and distributions from unconsolidated affiliate investments, less payments under onerous performance obligations, gains on extinguishment of debt, non-controlling interest, (income) loss on unconsolidated affiliate investments and transferred interest adjusted EBITDA. Adjusted EBITDA is a primary metric used in our short-term incentive program for compensating employees. In addition, Adjusted EBITDA is used as a supplemental liquidity and performance measure by our management and by external users of our financial statements, such as investors, commercial banks, research analysts and others, to assess:

- financial performance of our assets without regard to financing methods, capital structure or historical cost basis;
- the ability of our assets to generate cash sufficient to pay interest costs, support our indebtedness and make cash distributions to our unitholders and our general partner;
- our operating performance and return on capital as compared to those of other companies in the midstream energy sector, without regard to financing methods or capital structure; and
- the viability of acquisitions and capital expenditure projects and the overall rates of return on alternative investment opportunities.

The GAAP measures most directly comparable to adjusted EBITDA are net income (loss) from continuing operations and net cash provided by operating activities. Adjusted EBITDA should not be considered an alternative to, or more meaningful than, net income (loss) from continuing operations, operating income (loss), net cash provided by operating activities or any other measure of financial performance presented in accordance with GAAP. Adjusted

EBITDA may not be comparable to similarly-titled measures of other companies because other entities may not calculate adjusted EBITDA in the same manner.

Adjusted EBITDA does not include interest expense, income taxes or depreciation and amortization expense. Because we have borrowed money to finance our operations, interest expense is a necessary element of our costs and our ability to generate cash available for distribution. Because we use capital assets, depreciation and amortization are also necessary elements of our costs. Therefore, any measures that exclude these elements have material limitations. To compensate for these limitations, we believe that it is important to consider net income (loss) from continuing operations and net cash provided by operating activities as determined under GAAP, as well as adjusted EBITDA, to evaluate our overall performance.

The following tables reconcile adjusted EBITDA (in millions) to the most directly comparable GAAP measure for the periods indicated:

	Year Ended December 31,		
	2016	2015	2014
Reconciliation of net income (loss) from continuing operations to adjusted EBITDA			
Net income (loss) from continuing operations	$ (573.3)	$ (1,378.2)	$ 309.3
Interest expense	188.1	102.5	47.4
Depreciation and amortization	503.9	387.3	284.3
Impairments	566.3	1,563.4	—
(Gain) loss on disposition of assets	13.2	1.2	(0.1)
(Income) loss from unconsolidated affiliate investments (1)	19.9	(20.4)	(18.9)
Gain on extinguishment of debt	—	—	(3.2)
Distributions from unconsolidated affiliate investments (2)	25.0	42.7	23.7
Unit-based compensation	30.0	35.7	22.2
Income tax provision (benefit)	1.3	(0.5)	22.0
Loss on non-cash derivatives	20.1	7.7	22.4
Payments under onerous performance obligation offset to other current and long-term liabilities	(17.9)	(17.9)	(14.7)
Other (3)	6.9	11.3	(40.8)
Adjusted EBITDA before non-controlling interest	$ 783.5	$ 734.8	$ 653.6
Non-controlling interest share of adjusted EBITDA (4)	(8.9)	0.4	(0.2)
Transferred interest adjusted EBITDA (5)	—	(56.9)	(193.0)
Predecessor adjusted EBITDA (6)	—	—	(82.8)
Adjusted EBITDA, net to EnLink Midstream Partners, LP	$ 774.6	$ 678.3	$ 377.6

(1) The loss for the year ended December 31, 2016 includes an impairment loss of $20.1 million related to our December 2016 agreement to sell our investment in HEP. This sale is expected to close in the first quarter of 2017.

(2) Distributions for the year ended December 31, 2016 do not include $32.7 million of distributions received from HEP during the third quarter 2016 attributable to the redemption of preferred units. The preferred units were issued to us by HEP during the second and third quarters of 2016 for contributions of $29.5 million and $3.2 million, respectively.

(3) Includes accretion expense associated with asset retirement obligations; reimbursed employee costs from Devon and LPC, which are costs reimbursed to us by the previous employer in connection with the acquisition or merger; successful acquisition transaction costs, which we do not consider in determining adjusted EBITDA because operating cash flows are not used to fund such costs; and non-cash rent, which relates to lease incentives pro-rated over the lease term.

(4) Non-controlling interest share of adjusted EBITDA includes ENLC’s 16% share of adjusted EBITDA from EnLink Oklahoma T.O., NGP’s 49.9% share of adjusted EBITDA from the Delaware Basin JV and other minor non-controlling interests.

(5) Represents recast E2, Midstream Holdings and VEX adjusted EBITDA prior to the date of the drop down of the respective assets or interests from ENLC and Devon.

(6) Represents Predecessor’s adjusted EBITDA for the period from January 1, 2014 through March 7, 2014.

Distributable Cash Flow

We define distributable cash flow as adjusted EBITDA (as defined above), net to us, less interest expense (excluding amortization of the EnLink Oklahoma T.O. acquisition installment payable discount), adjustments for the redeemable non-controlling interest, non-cash litigation gain, interest rate swap proceeds, cash taxes and other and maintenance capital expenditures. Distributable cash flow is used as a supplemental liquidity measure by our management and by external users of our financial statements, such as investors, commercial banks, research analysts and others, to assess the ability of our assets to generate cash sufficient to pay interest costs, support our indebtedness and make cash distributions to our unitholders and our general partner.

Maintenance capital expenditures include capital expenditures made to replace partially-or fully-depreciated assets in order to maintain the existing operating capacity of the assets and to extend their useful lives. Examples of maintenance capital expenditures are expenditures to refurbish and replace pipelines and other gathering, well connection, compression and processing assets up to their original operating capacity, to maintain equipment reliability, integrity and safety and to address environmental laws and regulations.

The GAAP measure most directly comparable to distributable cash flow is net cash provided by operating activities. Distributable cash flow should not be considered an alternative to, or more meaningful than, net income (loss) from continuing operations, operating income (loss), net cash provided by operating activities or any other measure of financial performance presented in accordance with GAAP. Distributable cash flow has important limitations because it excludes some items that affect net income (loss) from continuing operations, operating income (loss) and net cash provided by operating activities. Distributable cash flow may not be comparable to similarly-titled measures of other companies because other entities may not calculate distributable cash flow in the same manner. To compensate for these limitations, we believe that it is important to consider net cash provided by operating activities as determined under GAAP, as well as distributable cash flow, to evaluate our overall liquidity.

Reconciliation of net cash provided by operating activities to adjusted EBITDA and Distributable Cash Flow (in millions):

	Year Ended December 31,		
	2016	2015	2014
Net cash provided by operating activities	$ 662.6	$ 645.6	$ 479.4
Interest expense, net (1)	135.3	104.0	48.6
Unit-based compensation (2)	—	—	2.8
Current income tax benefit	1.9	3.1	6.7
Distributions from unconsolidated affiliate investment in excess of earnings (3)	21.9	21.1	10.9
Other (4)	4.2	10.7	3.5
Changes in operating assets and liabilities which provided cash:			
Accounts receivable, accrued revenues, inventories and other	107.7	(201.6)	98.1
Accounts payable, accrued gas and crude oil purchases and other (5)	(150.1)	151.9	3.6
Adjusted EBITDA before non-controlling interest	$ 783.5	$ 734.8	$ 653.6
Non-controlling interest share of adjusted EBITDA (6)	(8.9)	0.4	(0.2)
Transferred interest adjusted EBITDA (7)	—	(56.9)	(193.0)
Predecessor adjusted EBITDA (8)	—	—	(82.8)
Adjusted EBITDA, net to EnLink Midstream Partners, LP	$ 774.6	$ 678.3	$ 377.6
Interest expense	(188.1)	(102.5)	(46.3)
Amortization of EnLink Oklahoma T.O. installment payable discount included in interest expense (9)	52.3	—	—
Non-cash adjustment for redeemable non-controlling interest	0.3	(1.8)	—
Litigation settlement adjustment	—	—	(4.7)
Interest rate swap (10)	0.4	(3.6)	(3.6)
Cash taxes and other	(1.9)	(2.8)	(0.1)
Maintenance capital expenditures (11)	(30.5)	(38.3)	(21.5)
Distributable cash flow	$ 607.1	$ 529.3	$ 301.4

(1) Net of amortization of debt issuance costs, discount and premium, and valuation adjustment for redeemable non-controlling interest included in interest expense but not included in net cash provided by operating activities.
(2) Represents Predecessor stock-based compensation contributed through equity and reflected in net distributions to Predecessor in cash flows from financing activities in the consolidated statements of cash flows.
(3) Distributions for the year ended December 31, 2016 do not include $32.7 million of distributions received from HEP during the third quarter 2016 attributable to the redemption of preferred units. The preferred units were issued to us by HEP during the second and third quarters of 2016 for contributions of $29.5 million and $3.2 million, respectively.
(4) Includes the following: successful acquisition transaction costs, non-cash rent, non-cash litigation gains and reimbursed employee costs from Devon and LPC.
(5) Net of payments under onerous performance obligation offset to other current and long-term liabilities.
(6) Non-controlling interest share of adjusted EBITDA includes ENLC’s 16% share of adjusted EBITDA from EnLink Oklahoma T.O., NGP’s 49.9% share of adjusted EBITDA from the Delaware Basin JV and other minor non-controlling interests.
(7) Represents recast E2, EMH and VEX adjusted EBITDA prior to the date of the drop down of the respective assets or interests from ENLC and Devon.
(8) Represents Predecessor’s adjusted EBITDA for the period from January 1, 2014 through March 7, 2014.
(9) Amortization of the EnLink Oklahoma T.O. installment payable discount is considered non-cash interest under our credit facility since the payment under the payable is consideration for the acquisition of the EnLink Oklahoma T.O. assets
(10) During the third quarter of 2016 and second quarters of 2015 and 2014, we entered into interest rate swap arrangements to mitigate our exposure to interest rate movements prior to our note issuances. The gain on settlement of the interest rate swaps was considered excess proceeds for the note issuance and is therefore excluded from distributable cash flow
(11) Maintenance capital expenditures presented in our reconciliation to distributable cash flows above include only our expenditures incurred at or after March 7, 2014. Maintenance capital expenditures prior to March 7, 2014 of $4.6 million were excluded from the reconciliation to distributable cash flow because they represent the cash flows of the Predecessor which were not available for distribution. Prior to March 7, 2014 these assets were owned by Devon, and therefore, all cash flow from these assets was distributed to Devon.

Gross Operating Margin

We define gross operating margin as revenues less cost of sales. We present gross operating margin by segment in “Results of Operations.” We disclose gross operating margin in addition to total revenue because it is the primary performance measure used by our management. We believe gross operating margin is an important measure because, in general, our business is to purchase and resell natural gas, NGLs, condensate and crude oil for a margin or to gather, process, transport or market natural gas, NGLs, condensate and crude oil for a fee. Operating expense is a separate measure used by management to evaluate operating performance of field operations. Direct labor and supervision, property insurance, property taxes, repair and maintenance, utilities and contract services comprise the most significant portion of our operating expenses. We do not deduct operating expenses from total revenue in calculating gross operating margin because these expenses are largely independent of the volumes we transport or process and fluctuate depending on the activities performed during a specific period. The GAAP measure most directly comparable to gross operating margin is operating income (loss). Gross operating margin should not be considered an alternative to, or more meaningful than, operating income (loss) as determined in accordance with GAAP. Gross operating margin has important limitations because it excludes all operating costs that affect operating income (loss) except cost of sales. Our gross operating margin may not be comparable to similarly-titled measures of other companies because other entities may not calculate gross operating margin in the same manner.

The following table provides a reconciliation of operating income (loss) to gross operating margin (in millions):

	Year Ended December 31,		
	2016	2015	2014
Operating income (loss)	$ (364.3)	$ (1,297.4)	$ 357.1
Add (deduct):			
Operating expenses	398.5	419.9	283.6
General and administrative expenses	119.3	132.4	94.5
Depreciation and amortization	503.9	387.3	284.3
(Gain) loss on sale of property	13.2	1.2	(0.1)
Gain on litigation settlement	—	—	(6.1)
Impairments	566.3	1,563.4	—
Gross operating margin	$ 1,236.9	$ 1,206.8	$ 1,013.3

Results of Operations

The table below sets forth certain financial and operating data for the periods indicated. We manage our operations by focusing on gross operating margin, which we define as operating revenue less cost of sales as reflected in the table below (in millions, except volumes):

	Year Ended December 31,		
	2016	2015	2014
Texas Segment			
Revenues	$ 1,068.3	$ 1,000.2	$ 1,032.4
Cost of sales	(483.4)	(412.2)	(456.9)
Total gross operating margin	$ 584.9	$ 588.0	$ 575.5
Louisiana Segment			
Revenues	$ 2,001.5	$ 1,840.3	$ 1,837.4
Cost of sales	(1,729.0)	(1,567.6)	(1,674.2)
Total gross operating margin	$ 272.5	$ 272.7	$ 163.2
Oklahoma Segment			
Revenues	$ 437.0	$ 187.0	$ 318.8
Cost of sales	(184.9)	(17.9)	(142.6)
Total gross operating margin	$ 252.1	$ 169.1	$ 176.2
Crude and Condensate Segment			
Revenues	$ 1,176.5	$ 1,498.2	$ 367.2
Cost of sales	(1,038.0)	(1,330.6)	(290.9)
Total gross operating margin	$ 138.5	$ 167.6	$ 76.3
Corporate			
Revenues	$ (430.9)	$ (73.6)	$ (48.0)
Cost of sales	419.8	83.0	70.1
Total gross operating margin	$ (11.1)	$ 9.4	$ 22.1
Total			
Revenues	$ 4,252.4	$ 4,452.1	$ 3,507.8
Cost of sales	(3,015.5)	(3,245.3)	(2,494.5)
Total gross operating margin	$ 1,236.9	$ 1,206.8	$ 1,013.3
Midstream Volumes:			
Texas (1)			
Gathering and Transportation (MMBtu/d)	2,622,600	2,849,600	2,958,000
Processing (MMBtu/d)	1,173,100	1,222,700	1,146,000
Louisiana (2)			
Gathering and Transportation (MMBtu/d)	1,676,600	1,468,300	615,200
Processing (MMBtu/d)	490,300	506,100	547,000
NGL Fractionation (Gals/d)	5,197,100	5,771,500	3,804,300
Oklahoma (3)			
Gathering and Transportation (MMBtu/d)	626,300	428,600	471,000
Processing (MMBtu/d)	574,900	359,600	442,000
Crude and Condensate (2)			
Crude Oil Handling (Bbls/d)	94,000	131,500	26,300
Brine Disposal (Bbls/d)	3,600	3,900	4,700

(1) Volumes include volumes per day based on 365-day period for the years ended December 31, 2016, 2015 and 2014 for Midstream Holdings operations. Volumes include volumes per day based on the 300-day period from March 7 to December 31, 2014 for the year ended December 31, 2014 for our legacy operations in Texas.

(2) Volumes include volumes per day based on the 300-day period from March 7 to December 31, 2014 for the year ended December 31, 2014 for our legacy operations. Midstream Holdings does not have any operations in Louisiana or Ohio.

(3) Volumes include volumes per day based on 365-day period for the years ended December 31, 2016, 2015 and 2014 respectively, for Midstream Holdings operations. We did not have any legacy operations in Oklahoma.

Year ended December 31, 2016 Compared to Year ended December 31, 2015

Gross Operating Margin. Gross operating margin was $1,236.9 million for the year ended December 31, 2016 compared to $1,206.8 million for the year ended December 31, 2015, an increase of $30.1 million, or 2.5%, due to the following:

- *Texas Segment.* Gross operating margin in the Texas segment decreased $3.1 million for the year ended December 31, 2016 compared to the year ended December 31, 2015. The Texas segment decrease was attributable to a decrease of $34.1 million in gross operating margin due to volume declines and expirations of certain higher margin contracts from our north Texas processing, gathering, and transportation assets. The gross operating margin decline due to volumes includes minimum volume commitment ("MVC") revenue from our contracts with Devon of $26.4 million for the year ended December 31, 2016 as compared to $3.8 million for the year ended December 31, 2015. This decrease from our north Texas assets was partially offset by gross operating margin contributions totaling $20.5 million from 2015 acquisitions on the MEGA system. In addition, volume growth in the MEGA system resulted in an additional increase in gross operating margin of $10.7 million between periods.

- *Louisiana Segment.* Gross operating margin in the Louisiana segment decreased $0.2 million for the year ended December 31, 2016 compared to the year ended December 31, 2015. The Louisiana segment realized a 1% decrease in gross operating margin from its NGL business as a result of declines in pipeline throughput and fractionation volumes, substantially offset by an increase in gross operating margin from the Louisiana gas business.

- *Oklahoma Segment.* Gross operating margin in the Oklahoma segment increased $83.0 million for the year ended December 31, 2016 compared to the year ended December 31, 2015. This increase was driven by a gross operating margin contribution of $82.0 million from the EnLink Oklahoma T.O. assets acquired in January 2016. In addition, our gross operating margin from our Cana gathering and processing assets increased by $5.8 million between periods primarily due to increased volumes from Devon, including MVC revenue from Devon of $10.8 million for the year ended December 31, 2016 as compared to $20.1 million for the year ended December 31, 2015. This increase was partially offset by a decline in gross operating margin of $5.4 million at our Northridge gathering and processing assets as a result of a decline in volumes and a rate reduction on a third party contract.

- *Crude and Condensate Segment.* Gross operating margin in the Crude and Condensate segment decreased $29.1 million for the year ended December 31, 2016 compared to the year ended December 31, 2015. A decrease of $24.7 million resulted from the termination of a customer contract during the second quarter of 2015 and included a $10.3 million early termination payment from the customer in 2015. The remaining decrease was primarily the result of volume declines throughout the Crude and Condensate segment.

- *Corporate Segment.* The Corporate segment included a loss from derivative activity of $11.1 million for the year ended December 31, 2016 compared to a gain of $9.4 million for the year ended December 31, 2015 related to the changes in fair value of our commodity swaps between periods. For the year ended December 31, 2016, there were realized gains of $9.0 million offset by $20.1 million in unrealized losses. For the year ended December 31, 2015, there were realized gains of $17.1 million partially offset by unrealized losses of $7.7 million.

Operating Expenses. Operating expenses were $398.5 million for the year ended December 31, 2016 compared to $419.9 million for the year ended December 31, 2015, a decrease of $21.4 million, or 5.1%. The primary contributors to the total decrease by segment were as follows (in millions):

	Year Ended December 31,		Change	
	2016	2015	$	%
Texas Segment	$ 168.5	$ 181.8	$ (13.3)	(7.3)%
Louisiana Segment	96.6	105.9	(9.3)	(8.8)%
Oklahoma Segment	52.1	30.3	21.8	71.9 %
Crude and Condensate Segment	81.3	101.9	(20.6)	(20.2)%
Total	$ 398.5	$ 419.9	$ (21.4)	(5.1)%

- *Texas Segment.* Operating expenses in the Texas segment decreased $13.3 million for the year ended December 31, 2016 compared to the year ended December 31, 2015. The decrease was primarily attributable to lower operating costs of $18.3 million resulting from overall cost reduction measures and lower rental expense on compressors. These decreases were partially offset by a $8.0 million increase in operating expenses attributable to the acquisitions in the MEGA system.

- *Louisiana Segment.* Operating expenses in the Louisiana segment decreased $9.3 million for the year ended December 31, 2016 compared to the year ended December 31, 2015 due to overall cost reduction measures, including cost savings from materials and supplies, construction fees and services and labor. In addition, rental expense decreased $1.0 million due to rental equipment that was returned in the first quarter of 2016.

- *Oklahoma Segment.* Operating expenses in the Oklahoma segment increased $21.8 million for the year ended December 31, 2016 compared to the year ended December 31, 2015. This increase was primarily attributable to the EnLink Oklahoma T.O. acquisition in January 2016.

- *Crude and Condensate Segment.* Operating expenses in the Crude and Condensate segment decreased $20.6 million for the year ended December 31, 2016 compared to the year ended December 31, 2015. This decrease was due primarily to decreased trucking volumes, which decreased labor, fuel and contractor costs, in addition to overall cost reduction measures.

General and Administrative Expenses. General and administrative expenses were $119.3 million for the year ended December 31, 2016 compared to $132.4 million for the year ended December 31, 2015, a decrease of $13.1 million, or 9.9%. The primary contributors to the decrease are as follows:

- unit-based compensation expense decreased $7.3 million due primarily to bonuses being paid in the form of units that immediately vested in March 2015;
- wages and salaries decreased $2.9 million due to a decrease in bonus expense;
- software consulting fees decreased $2.0 million due to completed implementation of new software;
- bad debt expense decreased $2.1 million;
- transition service fees related to acquisitions decreased $1.0 million;
- transaction costs related to acquisitions decreased $1.3 million;
- travel and training expense decreased $1.0 million; and
- rent expense increased $4.9 million related to new office leases that commenced during 2016.

Loss on Disposition of Assets. Loss on disposition of assets was $13.2 million for the year ended December 31, 2016 compared to a loss on disposition of assets of $1.2 million for the year ended December 31, 2015. The loss on disposition of assets for the year ended December 31, 2016 was primarily attributable to a $13.4 million loss on sale of the NTPL. The loss on disposition of assets for the year ended December 31, 2015 related to the retirement of a compressor due to fire damage.

Depreciation and Amortization. Depreciation and amortization expenses were $503.9 million for the year ended December 31, 2016 compared to $387.3 million for the year ended December 31, 2015, an increase of $116.6 million, or

30.1%. Of this increase, $88.6 million was attributable to the acquisition of the EnLink Oklahoma T.O. assets; $11.5 million was attributable to additional assets on the MEGA system; and $7.4 million was attributable to the Lobo plants. These increases were partially offset by a $14.4 million decrease in amortization attributable to the impairment of ORV intangible assets in the third quarter of 2015. The remaining increase in depreciation and amortization expense was primarily attributable to assets placed in service.

Impairments. Impairment expense was $566.3 million for the year ended December 31, 2016 compared to impairment expense of $1,563.4 million for the year ended December 31, 2015, a decrease of $997.1 million, or 63.8%. In the first quarter of 2016, we recognized an impairment on goodwill of $566.3 million related to our Texas and Crude and Condensate segments. For the year ended December 31, 2015, we recognized an impairment on goodwill of $1,328.2 million related to our Louisiana, Texas and Crude and Condensate segments and an impairment on intangible assets of $223.1 million in our Crude and Condensate segment. For the year ended December 31, 2015, we also recognized an impairment on property, plant and equipment of $12.1 million primarily related to costs associated with the cancellation of various projects. For more information, see the "Critical Accounting Policies" section below.

Interest Expense. Interest expense was $188.1 million for the year ended December 31, 2016 compared to $102.5 million for the year ended December 31, 2015, an increase of $85.6 million, or 83.5%. Net interest expense consisted of the following (in millions):

	Year Ended December 31, 2016	Year Ended December 31, 2015
Senior notes	$ 131.1	$ 106.0
Credit facility	11.7	7.9
Capitalized interest	(7.2)	(7.7)
Amortization of debt issue costs and net discount (premium)	53.1	0.2
Cash settlements on interest rate swap	(0.4)	(3.6)
Redeemable non-controlling interest	0.3	(1.8)
Other	(0.5)	1.5
Total	$ 188.1	$ 102.5

The increase in interest expense of $85.6 million was primarily due to an increase of $52.3 million attributable to the non-cash amortization of the discount related to the EnLink Oklahoma T.O. acquisition installment payments in 2016 and an increase of $25.1 million attributable to the issuance of $900.0 million aggregate principal amount of unsecured senior notes in May 2015 and the issuance of $500.0 million in aggregate principal amount of unsecured senior notes in July 2016.

Income (loss) from Unconsolidated Affiliate Investments. Loss from unconsolidated affiliate investments was $19.9 million for the year ended December 31, 2016 compared to income of $20.4 million for the year ended December 31, 2015, a decrease of $40.3 million. This decrease was primarily due to a $20.1 million impairment on our investment in HEP for the year ended December 31, 2016. In December 2016, we entered into an agreement to sell our ownership interest in HEP for approximately $193.1 million, and the transaction is expected to close in the first quarter of 2017. As a result, we reduced the carrying value of our investment to the expected sales price. In addition, the decrease in income from unconsolidated affiliate investments resulted from a $10.6 million decrease in income from our investment in HEP. Income from our investment in GCF also declined $9.2 million due to lower revenues as a result of lower pipeline and fractionator feed volumes, together with increased operating costs for major scheduled fractionator maintenance during the first quarter of 2016.

Year ended December 31, 2015 Compared to Year ended December 31, 2014

Gross Operating Margin. Gross operating margin was $1,206.8 million for the year ended December 31, 2015 compared to $1,013.3 million for the year ended December 31, 2014, an increase of $193.5 million, or 19.1%. Of this increase in gross operating margin:

- $85.9 million was attributable to the legacy Partnership assets for a full year of gross operating margin during 2015 as compared to ten months during 2014;
- $100.3 million was attributable to the LPC, Coronado, Chevron, and Matador acquisitions;

- $13.0 million was attributable to the VEX pipeline, which commenced operations in July 2014;
- $21.6 million was attributable the commercial start-up of five compression and condensate stabilization stations in ORV since the fourth quarter of 2014; and
- $51.5 million was attributable to the completion of the Cajun-Sibon expansion in September 2014.

This increase is partially offset by a:

- $57.4 million decrease in gross operating margin related to a decline in volumes on our Texas assets;
- $11.9 million decrease in gross operating margin related primarily to volume declines in our Louisiana gas business; and
- $6.7 million decrease in gross operating margin related to Midstream Holdings, which is the result of the new fixed-fee arrangements with Devon entered into in connection with the Business Combination.

Operating Expenses. Operating expenses were $419.9 million for the year ended December 31, 2015 compared to $283.6 million for the year ended December 31, 2014, an increase of $136.3 million, or 48.1%. Of this increase in operating expenses:

- $43.2 million was attributable to legacy Partnership assets for a full year of operating expense during 2015 as compared to ten months during 2014;
- $59.0 million was attributable to direct operating costs of the LPC, Coronado, Matador and Chevron acquisitions during 2014 and 2015;
- $7.9 million was due to our Cajun-Sibon expansion completed in September 2014;
- $10.7 million was attributable to ORV compression and stabilization facilities that have been placed in service since the fourth quarter of 2014;
- $6.7 million was attributable to our Bearkat natural gas processing plant and rich gas gathering system, which commenced operations in September 2014; and
- $5.2 million was attributable to an increase in Midstream Holdings' operating costs.

General and Administrative Expenses. General and administrative expenses were $132.4 million for the year ended December 31, 2015 compared to $94.5 million for the year ended December 31, 2014, an increase of $37.9 million, or 40.1%. The primary contributors to the increase were as follows:

- $18.8 million was attributable to the legacy Partnership assets for a full year of expenses during 2015 as compared to ten months during 2014;
- $6.0 million was attributable to certain bonuses paid in March 2015 in the form of unit awards that immediately vested;
- $5.4 million in transaction costs related to the EnLink Oklahoma T.O., Matador, LPC and Coronado acquisitions, as well as the VEX dropdown;
- $3.2 million in increased unit-based compensation expense;
- $2.3 million in increased bad debt expense; and
- $5.9 in increased salaries and wages due to an increase in headcount related to acquisitions during the year.

These increases were partially offset by a $2.4 million decrease attributable to Midstream Holdings. Prior to March 7, 2014, general and administrative expenses were allocated to Midstream Holdings by Devon.

Loss on Disposition of Assets. Loss on disposition of assets was $1.2 million for the year ended December 31, 2015 compared to a gain on disposition of assets of $0.1 million for the year ended December 31, 2014, an increase of $1.3 million. The loss on disposition of assets for the year ended December 31, 2015 related to the retirement of a compressor due to fire damage.

Depreciation and Amortization. Depreciation and amortization expenses were $387.3 million for the year ended December 31, 2015 compared to $284.3 million for the year ended December 31, 2014, an increase of $103.0 million, or 36.2%. Of this increase in depreciation and amortization expenses, $21.8 million was attributable to the legacy Partnership assets acquired in March 2014; $12.0 million was attributable to the Chevron acquisition in November 2014;

$6.8 million was attributable to the LPC asset acquisition in January 2015; $25.6 million was attributable to the Coronado asset acquisition in March 2015 and $1.7 million was attributable to the Matador asset acquisition in October 2015. The remaining increase in depreciation and amortization expense of $35.1 million was primarily attributable to new assets placed in service.

Impairments. Impairment expense was $1,563.4 million for the year ended December 31, 2015. We recognized an impairment on goodwill of $1,328.2 million related to our Louisiana, Texas, and Crude and Condensate segments and an impairment on intangible assets of $223.1 million in our Crude and Condensate segment for the year ended December 31, 2015. We also recognized an impairment on property, plant and equipment of $12.1 million for the year ended December 31, 2015 primarily related to costs associated with the cancellation of various capital projects. For more information, see "Critical Accounting Policies—Impairment of Goodwill" below.

Gain on Litigation Settlement. We recognized a gain on the settlement of a lawsuit of $6.1 million for the year ended December 31, 2014 due to a partial settlement of our claims against Texas Brine and its insurers. Additional claims related to this matter remain outstanding.

Interest Expense. Interest expense was $102.5 million for the year ended December 31, 2015 compared to $47.4 million for the year ended December 31, 2014, an increase of $55.1 million, or 116.2%. Of the increase in interest expense, $16.2 million was attributable to the number of days debt was outstanding in 2015 compared to 2014 because Midstream Holdings did not have any borrowings prior to March 7, 2014. Interest expense for the year ended December 31, 2015 also included interest expense for 365 days as compared to 300 days for the year ended December 31, 2014 (days from March 7, 2014 through December 31, 2014). In addition, average debt outstanding increased in 2015 as compared to 2014, which increased interest expense by $41.6 million but was partially offset by $5.2 million due to a decrease in average interest rates primarily related to our credit facility. Net interest expense consists of the following (in millions):

	Year Ended December 31,	
	2015	**2014**
Senior notes	$ 106.0	$ 55.6
Bank Credit Facility	7.9	5.8
Capitalized interest	(7.7)	(11.5)
Amortization of debt issue costs and net discount (premium)	0.2	(1.2)
Cash settlements on interest rate swap	(3.6)	(3.6)
Redeemable non-controlling interest	(1.8)	—
Other	1.5	2.3
Total	$ 102.5	$ 47.4

Income from Unconsolidated Affiliate Investments. Income from unconsolidated affiliate investments was $20.4 million for the year ended December 31, 2015 compared to $18.9 million for the year ended December 31, 2014, an increase of $1.5 million. This increase was primarily due to a $5.6 million increase attributable to our investment in HEP as a result of acquisition activity that occurred in 2015. This increase was partially offset by a decrease in our investment in GCF of $4.1 million due to lower throughput volume and decreased product price spreads.

Income Tax Expense. Income tax benefit was $0.5 million for the year ended December 31, 2015 compared to income tax expense of $22.0 million for the year ended December 31, 2014, a decrease of $22.5 million. The decrease in income tax expense primarily related to a reduction in our taxable income as compared to the Predecessor, which was a taxable entity prior to the Business Combination.

Critical Accounting Policies

The selection and application of accounting policies is an important process that has developed as our business activities have evolved and as the accounting rules have developed. Accounting rules generally do not involve a selection among alternatives, but involve an implementation and interpretation of existing rules, and the use of judgment to the specific set of circumstances existing in our business. Compliance with the rules necessarily involves reducing a number of very subjective judgments to a quantifiable accounting entry or valuation. We make every effort to properly comply with all applicable rules on or before their adoption, and we believe the proper implementation and consistent application of the accounting rules is critical.

Our critical accounting policies are discussed below. See “Item 8. Financial Statements and Supplementary Data— Note 2” for further details on our accounting policies.

Revenue Recognition and Commodity Risk Management. We recognize revenue for sales or services at the time the natural gas, NGL, condensate or crude oil is delivered or at the time the service is performed. We generally accrue one month of sales and the related gas, NGL, condensate or crude oil purchases and reverse these accruals when the sales and purchases are actually invoiced and recorded in the subsequent months. Actual results could differ from the accrual estimates.

We utilize extensive estimation procedures to determine the sales and cost of gas, NGL, condensate or crude oil purchase accruals for each accounting cycle. Accruals are based on estimates of volumes flowing each month from a variety of sources. We use actual measurement data, if it is available, and will use such data as producer/shipper nominations, prior month average daily flows, estimated flow for new production and estimated end-user requirements (all adjusted for the estimated impact of weather patterns) when actual measurement data is not available. Throughout the month following production, actual measured sales and transportation volumes are received and invoiced and used in a process referred to as “actualization.” Through the actualization process, any estimation differences recorded through the accrual are reflected in the subsequent month’s accounting cycle when the accrual is reversed and actual amounts are recorded. Actual volumes purchased, processed or sold may differ from the estimates due to a variety of factors including, but not limited to: actual wellhead production or customer requirements being higher or lower than the amount nominated at the beginning of the month; liquids recoveries being higher or lower than estimated because gas processed through the plants was richer or leaner than estimated; NGL composition of purchases, sales and inventory being different than estimated; the estimated impact of weather patterns being different from the actual impact on sales and purchases; and pipeline maintenance or allocation causing actual deliveries of gas to be different than estimated. We believe that our accrual process for sales and purchases provides a reasonable estimate of such sales and purchases.

We engage in price risk management activities in order to minimize the risk from market fluctuations in the price of natural gas, NGLs, crude oil and condensate. We also manage our price risk related to future physical purchase or sale commitments by entering into either corresponding physical delivery contracts or financial instruments with an objective to balance our future commitments and significantly reduce our risk to the movement in natural gas, NGL and crude oil prices.

We use derivatives to hedge against changes in cash flows related to product prices, as opposed to their use for trading purposes. ASC 815, *Derivatives and Hedging*, requires that all derivatives and hedging instruments are recognized as assets or liabilities at fair value. We manage our price risk related to future physical purchase or sale commitments for physical quantities of natural gas, NGLs and crude oil by entering into either corresponding physical delivery contracts or financial instruments with an objective to balance future commitments and significantly reduce risk related to the movement in natural gas, NGL and crude oil prices. However, we are subject to counter-party risk for both the physical and financial contracts. Our hedging contracts qualify as derivatives and we use mark-to-market accounting for both physical and financial contracts of the energy trading business. Accordingly, any gain or loss associated with changes in the fair value of derivatives and physical delivery contracts relating to our hedging activities are recognized currently in earnings as gain on derivatives.

Impairment of Long-Lived Assets. In accordance with ASC 360, *Property, Plant and Equipment*, we evaluate long-lived assets, including related intangibles, of identifiable business activities for impairment when events or changes in circumstances indicate, in management’s judgment, that the carrying value of such assets may not be recoverable. The determination of whether impairment has occurred is based on management’s estimate of undiscounted future cash flows attributable to the assets as compared to the carrying value of the assets. If impairment has occurred, the amount of the impairment recognized is determined by estimating the fair value for the assets and recording a provision for loss if the carrying value is greater than fair value.

When determining whether impairment of one of our long-lived assets has occurred, we must estimate the undiscounted cash flows attributable to the asset. Our estimate of cash flows is based on assumptions regarding:

- the future fee-based rate of new business or contract renewals;
- the purchase and resale margins on natural gas, NGLs, crude oil and condensate;
- the volume of gas, NGLs, crude oil and condensate available to the asset;
- markets available to the asset;
- operating expenses; and
- future natural gas, NGL product, crude oil and condensate prices.

The amount of availability of gas, NGLs, crude oil and condensate to an asset is sometimes based on assumptions regarding future drilling activity, which may be dependent in part on natural gas, NGL, crude oil and condensate prices. Projections of gas, NGL, crude oil and condensate volumes and future commodity prices are inherently subjective and contingent upon a number of variable factors, including but not limited to:

- changes in general economic conditions in regions in which our markets are located;
- the availability and prices of natural gas, NGLs, crude oil and condensate supply;
- our ability to negotiate favorable sales agreements;
- the risks that natural gas, NGLs, crude oil and condensate exploration and production activities will not occur or be successful;
- our dependence on certain significant customers, producers and transporters of natural gas, NGLs, crude oil and condensate; and
- competition from other midstream companies, including major energy companies.

Any significant variance in any of the above assumptions or factors could materially affect our cash flows, which could require us to record an impairment of an asset.

During 2016 and 2015, we reviewed our various assets groups for impairment due to the triggering events described in the goodwill impairment analysis below. During 2015, the undiscounted cash flows related to one of our assets groups in the Crude and Condensate segment were not in excess of its related carrying value. We estimated the fair value of this reporting unit and determined the fair of the intangible assets was not in excess of their carrying value. This resulted in a $223.1 million impairment of intangible assets in our Crude and Condensate segment, and this non-cash impairment charge is included as an impairment loss on the consolidated statements of operations for the year ended December 31, 2015. We utilized Level 3 fair value measurements in our impairment analysis of this definite-lived intangible asset, which included discounted cash flow assumptions by management consistent with those utilized in our goodwill impairment analysis.

Additionally, we recognized a $12.1 million impairment on property, plant and equipment, primarily related to costs associated with the cancellation of various capital projects in our Texas, Louisiana and Crude and Condensate segments for the year ended December 31, 2015. For the year ended December 31, 2016, we did not identify any triggering events that would indicate impairment on our property, plant and equipment.

Impairment of Goodwill. We conduct our annual goodwill impairment test in the fourth quarter each year. Goodwill is the cost of an acquisition less the fair value of the net identifiable assets of the acquired business. We evaluate goodwill for impairment annually as of October 31, and whenever events or changes in circumstances indicate it is more likely than not that the fair value of a reporting unit is less than its carrying amount. We first assess qualitative factors to evaluate whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount as the basis for determining whether it is necessary to perform the two-step goodwill impairment test. We may elect to perform the two-step goodwill impairment test without completing a qualitative assessment. If a two-step goodwill impairment test is elected or required, the first step involves comparing the fair value of the reporting unit to its carrying amount. If the carrying amount of a reporting unit exceeds its fair value, the second step of the process involves comparing the implied fair value to the carrying value of the goodwill for that reporting unit. If the carrying value of the goodwill of a reporting unit exceeds the implied fair value of that goodwill, the excess of the carrying value over the implied fair value is recognized as an impairment loss.

We perform our goodwill assessments at the reporting unit level for all reporting units. We use a discounted cash flow analysis to perform the assessments. Key assumptions in the analysis include the use of an appropriate discount rate, terminal year multiples and estimated future cash flows, including volume and price forecasts and estimated operating expense and general and administrative costs. In estimating cash flows, we incorporate current and historical market and financial information, among other factors.

During the third quarter of 2015, we determined that sustained weakness in the overall energy sector, driven by low commodity prices together with a decline in our unit price, caused a change in circumstances warranting an interim impairment test. We also performed our annual impairment analysis during the fourth quarter of 2015. Although our established annual effective date for this goodwill analysis is October 31, we updated the effective date for this impairment analysis for the 2015 annual period to December 31, 2015 due to continued declines in commodity prices and our unit price during the fourth quarter of 2015.

Using the fair value approaches described above, in step one of the goodwill impairment test, we determined that the estimated fair values of our Louisiana, Texas and Crude and Condensate reporting unit were less than their carrying amounts, primarily related to commodity prices, volume forecasts and discount rates. The second step of the goodwill impairment test measures the amount of impairment loss and allocated the estimated fair value of the reporting unit among all of the assets and liabilities of the reporting unit as if the reporting unit had been acquired in a business combination. Based on this analysis, a goodwill impairment loss for our Louisiana, Texas, and Crude and Condensate reporting units in the amount of $1,328.2 million was recognized for the year ended December 31, 2015 and is included as an impairment loss in the consolidated statements of operations.

During February 2016, we determined that continued further weakness in the overall energy sector, driven by low commodity prices together with a further decline in our unit price subsequent to year-end, caused a change in circumstances warranting an interim impairment test. Based on these triggering events, we performed a goodwill impairment analysis in the first quarter of 2016 on all reporting units. Based on this analysis, a goodwill impairment loss for our Texas and Crude and Condensate reporting units in the amount of $566.3 million was recognized in the first quarter of 2016 and is included as an impairment loss in the consolidated statement of operations for the year ended December 31, 2016.

We concluded that the fair value of our Oklahoma reporting unit exceeded its carrying value, and the amount of goodwill disclosed on the consolidated balance sheet associated with this reporting unit is recoverable for each of the impairment testing periods during 2015 and 2016. Therefore, no other goodwill impairment was identified or recorded for this reporting unit as a result of our goodwill impairment analyses.

During our annual impairment test for 2016 performed as of October 31, 2016, we determined that no further impairments were required for the year ended December 31, 2016. The estimated fair value of our reporting units may be impacted in the future by a further decline in our unit price or a continuing prolonged period of lower commodity prices which may adversely affect our estimate of future cash flows, both of which could result in future goodwill impairment charges for our reporting units.

Our impairment determinations involved significant assumptions and judgments, as discussed above. Differing assumptions regarding any of these inputs could have a significant effect on the various valuations. If actual results are not consistent with our assumptions and estimates, or our assumptions and estimates change due to new information, we may be exposed to additional goodwill impairment charges, which would be recognized in the period in which the carrying value exceeds fair value.

Depreciation Expense and Cost Capitalization. Our assets consist primarily of natural gas, NGL, condensate and crude oil gathering pipelines, processing plants, condensate stabilization facilities, transmission pipelines and trucks. We capitalize all construction-related direct labor and material costs, as well as indirect construction costs. Indirect construction costs include general engineering and the costs of funds used in construction. Capitalized interest represents the cost of funds used to finance the construction of new facilities and is expensed over the life of the constructed assets through the recording of depreciation expense. We capitalize the costs of renewals and betterments that extend the useful life while we expense the costs of repairs, replacements and maintenance projects as incurred.

We generally calculate depreciation using the straight-line method over the estimated useful life of the assets. Certain assets such as land, NGL line pack, natural gas line pack and crude oil line pack are non-depreciable. The computation of depreciation expense requires judgment regarding the estimated useful lives and salvage value of assets. As circumstances warrant, we may review depreciation estimates to determine if any changes are needed. Such changes could involve an increase or decrease in estimated useful lives or salvage values, which would impact future depreciation expense.

Commodity Price Risk

We are subject to significant risks due to fluctuation in commodity prices. Our exposure to these risks is primarily in the gas processing component of our business. Processing margin, POL and POP contracts are three types of contracts under which we process gas and are exposed to commodity price risk. For the year ended December 31, 2016, approximately 3.0% of our contracts, based on gross operating margin, were processed under POL and POP contracts. A portion of the volume of inlet gas at our south Louisiana and north Texas processing plants is settled under POL agreements. Under these contracts we receive a fee in the form of a percentage of the liquids recovered, and the producer bears all the costs of the natural gas volumes lost ("shrink"). All of the natural gas processed by our Midmar plants in the Permian Basin are POP-based contracts. Under these contracts, we receive a fee as a portion of the proceeds of the sale of natural gas and liquids. Accordingly, our revenues under these contracts are directly impacted by the market price of natural gas and NGLs.

We also realize gross operating margin under processing margin contracts. For the year ended December 31, 2016, approximately 0.9% of our contracts, based on gross operating margin, were under processing margin contracts. We have a number of processing margin contracts on our Plaquemine and Pelican processing plants. Under this type of contract, we pay the producer for the full amount of inlet gas to the plant, and we make a margin based on the difference between the value of liquids recovered from the processed natural gas as compared to the value of the natural gas shrink and the cost of fuel used in processing. The shrink and fuel losses are referred to as "plant thermal reduction" or "PTR."

The prices of crude oil, condensate, natural gas and NGLs were extremely volatile during 2016. Crude oil, weighted average NGL, and natural gas prices increased 46%, 53% and 60%, respectively, from January 1, 2016 to December 31, 2016. We expect this volatility to continue. For example, crude oil prices (based on the NYMEX futures daily close prices for the prompt month) in 2016 ranged from a high of $54.06 per Bbl in December 2016 to a low of $26.21 per Bbl in February 2016. Weighted average NGL prices in 2016 (based on the Oil Price Information Service ("OPIS") Napoleonville daily average spot liquids prices) ranged from a high of $0.66 per gallon in December 2016 to a low of $0.31 per gallon in January 2016. Natural gas prices (based on Gas Daily Henry Hub closing prices) during 2016 ranged from a high of $3.93 per MMBtu in December 2016 to a low of $1.64 per MMBtu in March 2016.

Changes in commodity prices may also indirectly impact our profitability by influencing drilling activity and well operations, and thus the volume of gas, NGLs, crude oil and condensate connected to or near our assets and on our fees earned for transportation between certain market centers. Low prices for these products could reduce the demand for our services and volumes on our systems. The volatility in commodity prices may cause our gross operating margin and cash flows to vary widely from period to period. Our hedging strategies may not be sufficient to offset price volatility risk and, in any event, do not cover all of our throughput volumes. For a discussion of our risk management activities, please read "Item 7A. Quantitative and Qualitative Disclosures about Market Risk."

Liquidity and Capital Resources

Cash Flows from Operating Activities. Net cash provided by operating activities was $662.6 million, $645.6 million and $479.4 million for the years ended December 31, 2016, 2015 and 2014, respectively. Operating cash flows and changes in working capital for 2016, 2015 and 2014 were as follows (in millions):

	Year Ended December 31,		
	2016	2015	2014
Operating cash flows before working capital	$ 638.1	$ 613.7	$ 590.0
Changes in working capital	24.5	31.9	(110.6)
Total	$ 662.6	$ 645.6	$ 479.4

Operating cash flows before changes in working capital increased $24.4 million for the year ended December 31, 2016 compared to the year ended December 31, 2015 due primarily to an increase in gross operating margin in our Oklahoma segment from the acquisition of the EnLink Oklahoma T.O. assets, which was offset partially by a decrease in gross operating margin in our Crude and Condensate segment due to lower volumes and the termination of a customer contract during the second quarter of 2015. The changes in working capital for the year ended December 31, 2016 were due primarily to fluctuations in trade receivable and payable balances due to timing of collection and payments and changes in inventory balances attributable to normal operating fluctuations.

Cash Flows from Investing Activities. Net cash used in investing activities was $1,358.1 million, $1,097.3 million and $1,211.8 million for the years ended December 31, 2016, 2015 and 2014, respectively. Our primary sources and uses of cash related to investing activities for the years ended December 31, 2016, 2015 and 2014 were as follows (in millions):

	Year Ended December 31,		
	2016	2015	2014
Growth capital expenditures	$ 632.5	$ 530.0	$ 758.9
Maintenance capital expenditures	30.5	42.3	37.1
Acquisition of business	769.3	524.2	421.1
Proceeds from sale of property	(93.1)	(1.0)	(0.1)
Proceeds from insurance settlement	(0.3)	(2.9)	—
Investment in unconsolidated affiliate investments	73.8	25.8	5.7
Distribution from unconsolidated affiliate investments in excess of earnings	(54.6)	(21.1)	(10.9)
Total	$ 1,358.1	$ 1,097.3	$ 1,211.8

We consider a number of factors in determining whether our capital expenditures are growth capital expenditures or maintenance capital expenditures. Growth capital expenditures generally include capital expenditures made for acquisitions or capital improvements that we expect will increase our asset base, operating income or operating capacity over the long-term. Examples of growth capital expenditures include the acquisition of assets and the construction or development of additional pipeline, storage, well connections, gathering or processing assets, in each case, to the extent such capital expenditures are expected to expand our asset base, operating capacity or our operating income.

Maintenance capital expenditures include capital expenditures made to replace partially or fully depreciated assets in order to maintain the existing operating capacity of the assets and to extend their useful lives. Examples of maintenance capital expenditures are expenditures to refurbish and replace pipelines, gathering assets, well connections, compression assets and processing assets up to their original operating capacity, or to maintain pipeline and equipment reliability, integrity and safety and to address environmental laws and regulations.

Growth capital expenditures increased $102.5 million for the year ended December 31, 2016 compared to the year ended December 31, 2015. The increase in growth capital expenditures was primarily attributable to gas processing and gathering expansion projects for EnLink Oklahoma T.O and the construction of the Lobo II plant and gathering pipeline, which is owned by the Delaware Basin JV. Growth capital expenditures decreased $228.9 million for the year ended December 31, 2015 as compared to the year ended December 31, 2014. The decrease was primarily attributable to a decrease in growth capital expenditures of $281.2 million related to our Cajun Sibon expansion project, which went into service in September 2014. This decrease is partially offset by an increase in capital expenditures of $46.7 million related to our ORV assets.

Maintenance capital expenditures decreased $11.8 million for the year ended December 31, 2016 compared to the year ended December 31, 2015. The decrease was primarily attributable to decreases in compressor overhauls in our Texas segment, and other repairs in our Oklahoma and Louisiana segments. Maintenance capital expenditures increased $5.2 million for the year ended December 31, 2015 compared to the year ended December 31, 2014. The increase was primarily attributable to compressor overhauls and repairs in our Texas and Oklahoma segments.

Acquisition expenditures increased $245.1 million for the year ended December 31, 2016 compared to the year ended December 31, 2015. Acquisitions for the year ended December 31, 2016 included the acquisition of the EnLink Oklahoma T.O. assets. Acquisition expenditures increased $103.1 million for the year ended December 31, 2015 compared to the year ended December 31, 2014. Acquisitions of businesses for the year ended December 31, 2015 included LPC, Coronado, Matador and Deadwood. Acquisition of businesses for the year ended December 31, 2014 included the Chevron, E2 and VEX Interests.

Proceeds from sale of property increased $92.1 million for the year ended December 31, 2016 compared to the year ended December 31, 2015. The increase was due primarily to the sale of the NTPL in December 2016 for $84.6 million.

Investment in unconsolidated affiliate investments increased $48.0 million for the year ended December 31, 2016 compared to the year ended December 31, 2015. Investments in unconsolidated affiliate investments for the year ended December 31, 2016 included $45.0 million in contributions to our investment in HEP, including $32.7 million of contributions to HEP for preferred units, which were subsequently redeemed during the third quarter of 2016 and classified as a distribution from unconsolidated affiliate investments in excess of earnings. In addition, investments in unconsolidated affiliate investments for the year ended December 31, 2016 included a $28.8 million contribution to the Cedar Cove JV. Investments in unconsolidated affiliate investments for the years ended December 31, 2015 and 2014 consisted of our contributions to HEP.

Cash Flows from Financing Activities. Net cash provided by financing activities was $701.2 million, $448.0 million and $742.0 million for the years ended December 31, 2016, 2015 and 2014, respectively. Our primary financing activities consisted of the following (in millions):

	Year Ended December 31,		
	2016	2015	2014
Net borrowings (repayments) on our credit facility	$ (294.2)	$ 176.8	$ (140.0)
Unsecured senior notes borrowings	499.3	893.3	1,600.7
Redemption of 2018 notes	—	—	(760.3)
Partial redemption of 2022 notes	—	—	(36.4)
Net repayments on E2 credit facility	—	—	(13.8)
Debt financing costs	(4.6)	(9.5)	(18.5)
Proceeds from issuance of common units (including units issued to general partner)	167.5	74.4	412.0
Proceeds from issuance of Preferred Units	724.1	—	—
Contributions by non-controlling partners	207.4	16.4	6.3
Contributions from Devon	1.5	27.8	105.7

For the year ended December 31, 2016, contributions by non-controlling partners included $144.4 million in contributions from NGP to the Delaware Basin JV, which consisted of an initial contribution of $114.3 million that the Delaware Basin JV distributed to us at the formation of the joint venture to reimburse us for capital spent to the date of formation on existing assets, as well as $30.1 million for NGP's share of ongoing projects. Contributions by non-controlling partners also included $39.5 million from ENLC for its share of costs incurred related to EnLink Oklahoma T.O.

Distributions to unitholders, Devon and our general partner also represent a primary use of cash in financing activities. Total unitholder cash distributions made during the years ended December 31, 2016, 2015 and 2014 were as follows (in millions):

	Year Ended December 31,		
	2016	2015	2014
Common units	$ 520.3	$ 436.1	$ 222.7
General partner interest (including incentive distribution rights)	58.7	43.2	17.1
Distributions to non-controlling interests (1)	10.0	66.5	159.5
Distributions to Devon for net assets acquired (2)	—	166.7	—

(1) Represents distributions to ENLC relating to ENLC's prior ownership in EnLink Midstream Holdings, LP during 2015, distributions to redeem the non-controlling interest in one of the E2 entities and ENLC's ownership of EnLink Oklahoma T.O. during 2016.
(2) Represents distributions to Devon relating to the VEX assets.

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In order to reduce our interest costs, we do not borrow money to fund outstanding checks until they are presented to the bank. Fluctuations in drafts payable are caused by timing of disbursements, cash receipts and draws on our credit facility. We borrow money under our credit facility to fund checks as they are presented. Changes in drafts payable were as follows (in millions):

	Year Ended December 31,		
	2016	2015	2014
Decrease in drafts payable	$ —	$ (12.7)	$ 10.2

Uncertainties. We own and operate a high-pressure pipeline and underground natural gas and NGL storage reservoirs and associated facilities near Bayou Corne, Louisiana. In August 2012, a large sinkhole formed in the vicinity of this pipeline and underground storage reservoirs, resulting in damage to certain of our facilities. We are seeking to recover our losses from responsible parties. We have sued Texas Brine Company, LLC ("Texas Brine"), the operator of a failed cavern in the area, and its insurers seeking recovery for these losses. We have also sued Occidental Chemical Company and Legacy Vulcan Corp. f/k/a Vulcan Materials Company, two Chlor-Alkali plant operators that participated in Texas Brine's operational decisions regarding mining the failed cavern. We also filed a claim with our insurers, which our insurers denied. We disputed the denial and have also sued our insurers. In August 2014, we received a partial settlement with respect to the Texas Brine claims in the amount of $6.1 million, but additional claims remain outstanding. We cannot give assurance that we will be able to fully recover our losses through insurance recovery or claims against responsible parties.

In June 2014, a group of landowners in Assumption Parish, Louisiana added our subsidiary, EnLink Processing Services, LLC, as a defendant in a pending lawsuit they had filed against Texas Brine, Occidental Chemical Corporation and Vulcan Materials Company relating to claims arising from the Bayou Corne sinkhole. The suit is pending in the 23rd Judicial Court, Assumption Parish, Louisiana. Although plaintiffs' claims against the other defendants have been pending since October 2012, plaintiffs are now alleging that EnLink Processing Services, LLC's negligence also contributed to the formation of the sinkhole. The amount of damages is unspecified. The validity of the causes of action, as well as our costs and legal exposure, if any, related to the lawsuit are not currently determinable. We intend to vigorously defend the case. We have also filed a claim for defense and indemnity with our insurers.

Capital Requirements. We expect our 2017 capital expenditures, including capital contributions to our unconsolidated affiliate investments, to be as follows (in millions):

	2017
Growth capital expenditures	
Texas segment	$ 110 - 140
Louisiana segment	88 - 102
Oklahoma segment (1) (2)	360 - 460
Crude and Condensate segment	35 - 45
Corporate segment	17 - 23
Total growth capital expenditures	$ 610 - 770
Less: Growth capital expenditures funded by joint venture partners (3)	(105 - 125)
Growth capital expenditures, attributable to the Partnership	$ 505 - 645
Maintenance capital expenditures	$ 38 - 48

(1) Projected growth capital expenditure range for 2017 excludes the $250 million installment payable related to the acquisition of EnLink Oklahoma T.O. in January 2016.
(2) Includes projected growth capital contributions related to our non-controlling interest share of the Cedar Cove JV.
(3) Includes growth capital expenditures that will be contributed by other entities and relate to the non-controlling interest share of our consolidated entities. These contributions include contributions by ENLC to EnLink Oklahoma T.O., contributions by NGP to the Delaware Basin JV and contributions by Marathon to the Ascension JV.

Our primary capital projects for 2017 include the construction of our Chisholm II and III plant expansions, the development of additional gathering and compression assets in the Oklahoma and the Midland Basin and contributions to the Delaware Basin JV, Cedar Cove JV, and Ascension JV.

We expect to fund the growth capital expenditures from the proceeds of planned and completed asset sales, at-the-market equity issuances and borrowings under our credit facility, as well as contributions by joint venture partners that relate to the non-controlling interest share of our consolidated entities. We expect to fund our 2017 maintenance capital expenditures from operating cash flows. In 2017, it is possible that not all of the planned projects will be commenced or completed. Our ability to pay distributions to our unitholders, and to fund planned capital expenditures and to make acquisitions will depend upon our future operating performance, which will be affected by prevailing economic conditions in the industry and financial, business and other factors, some of which are beyond our control.

Off-Balance Sheet Arrangements. We had no off-balance sheet arrangements as of December 31, 2016, 2015 and 2014.

Total Contractual Cash Obligations. A summary of our total contractual cash obligations as of December 31, 2016 is as follows (in millions):

	Payments Due by Period						
	Total	2017	2018	2019	2020	2021	Thereafter
Long-term debt obligations	$3,162.5	$ —	$ —	$400.0	$ —	$ —	$2,762.5
Credit facility	120.0	—	—	—	120.0	—	—
Installment payable obligations (1)	500.0	250.0	250.0	—	—	—	—
Interest payable on fixed long-term debt obligations	1,966.0	144.3	144.3	138.9	133.5	133.5	1,271.5
Capital lease obligations	7.5	2.0	2.2	1.6	1.7	—	—
Operating lease obligations	123.8	16.2	15.4	10.9	8.6	8.7	64.0
Purchase obligations	13.4	13.4	—	—	—	—	—
Delivery contract obligation	44.8	17.9	17.9	9.0	—	—	—
Pipeline capacity and deficiency agreements (2)	95.2	13.7	15.3	11.6	8.1	8.1	38.4
Inactive easement commitment (3)	10.0	—	—	—	—	—	10.0
Total contractual obligations	$6,043.2	$457.5	$445.1	$572.0	$271.9	$150.3	$4,146.4

(1) Amounts relate to our partial consideration of the acquisition of the EnLink Oklahoma T.O. assets with balances paid on January 7, 2017 and due on January 7, 2018.
(2) Consists of pipeline capacity payments for firm transportation and deficiency agreements.
(3) Amounts related to inactive easements paid as utilized by us with balance due at end of 10 years if not utilized.

In January 2017, we paid the $250.0 million installment payable obligation related to the EnLink Oklahoma T.O. acquisition, which was due on January 7, 2017. We funded this installment payment using various sources, including $84.6 million in proceeds received from the sale of NTPL, proceeds from equity issuances through our ATM and borrowings under our credit facility. Our remaining contractual cash obligations for 2017 are expected to be funded from cash flows from our operations.

The above table does not include any physical or financial contract purchase commitments for natural gas due to the nature of both the price and volume components of such purchases, which vary on a daily or monthly basis. Additionally, we do not have contractual commitments for fixed price and/or fixed quantities of any material amount.

The interest payable under our credit facility is not reflected in the above table because such amounts depend on outstanding balances and interest rates, which will vary from time to time. However, given the same borrowing amount and rates in effect at December 31, 2016, our cash obligation for interest expense on our credit facility would be approximately $2.8 million per year.

Indebtedness

As of December 31, 2016 and 2015, long-term debt consisted of the following (in millions):

	December 31, 2016			December 31, 2015		
	Outstanding Principal	Premium (Discount)	Long-Term Debt	Outstanding Principal	Premium (Discount)	Long-Term Debt
Partnership credit facility, due 2020 (1)	$ 120.0	$ —	$ 120.0	$ 414.0	$ —	$ 414.0
2.70% Senior unsecured notes due 2019	400.0	(0.3)	399.7	400.0	(0.4)	399.6
7.125% Senior unsecured notes due 2022	162.5	16.0	178.5	162.5	18.9	181.4
4.40% Senior unsecured notes due 2024	550.0	2.5	552.5	550.0	2.9	552.9
4.15% Senior unsecured notes due 2025	750.0	(1.1)	748.9	750.0	(1.2)	748.8
4.85% Senior unsecured notes due 2026	500.0	(0.7)	499.3	—	—	—
5.60% Senior unsecured notes due 2044	350.0	(0.2)	349.8	350.0	(0.2)	349.8
5.05% Senior unsecured notes due 2045	450.0	(6.6)	443.4	450.0	(6.9)	443.1
Other debt	—	—	—	0.2	—	0.2
Debt classified as long-term	$ 3,282.5	$ 9.6	$ 3,292.1	$ 3,076.7	$ 13.1	$ 3,089.8
Debt issuance cost (2)			(24.1)			(23.0)
Long-term debt, net of unamortized issuance cost			$ 3,268.0			$ 3,066.8

(1) Bears interest based on Prime and/or LIBOR plus an applicable margin. The effective interest rate was 2.3% and 1.8% at December 31, 2016 and 2015, respectively.
(2) Net of amortization of $8.3 million and $4.7 million at December 31, 2016 and 2015, respectively.

Credit Facility

We have a $1.5 billion unsecured revolving credit facility including a $500.0 million letter of credit subfacility, that matures on March 6, 2020. Under our credit facility, we are permitted to (1) subject to certain conditions and the receipt of additional commitments by one or more lenders, increase the aggregate commitments under our credit facility by an additional amount not to exceed $500.0 million and (2) subject to certain conditions and the consent of the requisite lenders, on two separate occasions extend the maturity date of our credit facility by one year on each occasion. Our credit facility contains certain financial, operational and legal covenants. Among other things, these covenants include maintaining a ratio of consolidated indebtedness to consolidated EBITDA (which is defined in our credit facility and includes projected EBITDA from certain capital expansion projects) of no more than 5.0 to 1.0. If we consummate one or more acquisitions in which the aggregate purchase price is $50.0 million or more, we can elect to increase the maximum allowed ratio of consolidated indebtedness to consolidated EBITDA to 5.5 to 1.0 for the quarter of the acquisition and the three following quarters.

Borrowings under our credit facility bear interest at our option at the Eurodollar Rate (the LIBOR Rate) plus an applicable margin (ranging from 1.00% to 1.75%) or the Base Rate (the highest of the Federal Funds Rate plus 0.50%, the 30-day Eurodollar Rate plus 1.0% or the administrative agent’s prime rate) plus an applicable margin (ranging from zero percent to 0.75%).

If we breach certain covenants governing our credit facility, amounts outstanding under our credit facility, if any, may become due and payable immediately. We expect to be in compliance with the covenants in credit facility for at least the next twelve months.

As of December 31, 2016, there were $11.5 million in outstanding letters of credit and $120.0 million in outstanding borrowings under our credit facility, leaving approximately $1.4 billion available for future borrowing based on the borrowing capacity of $1.5 billion.

Senior Unsecured Notes

On March 7, 2014, we recorded $196.5 million in aggregate principal amount of 7.125% senior unsecured notes (the “2022 Notes”) due on June 1, 2022 in the Business Combination. The interest payments on the 2022 Notes are due semi-annually in arrears in June and December. As a result of the Business Combination, the 2022 Notes were recorded at fair value in accordance with acquisition accounting at an amount of $226.0 million, including a premium of $29.5 million. On July 20, 2014, we redeemed $18.5 million aggregate principal amount of the 2022 Notes for $20.0 million, including accrued interest. On September 20, 2014, we redeemed an additional $15.5 million aggregate principal amount of the 2022 Notes for $17.0 million, including accrued interest. We recorded a gain on extinguishment of debt related to the redemption of the 2022 Notes of $2.4 million for the year ended December 31, 2014.

On March 19, 2014, we issued $1.2 billion aggregate principal amount of unsecured senior notes, consisting of $400.0 million aggregate principal amount of our 2.700% senior notes due 2019 (the “2019 Notes”), $450.0 million aggregate principal amount of our 4.400% senior notes due 2024 (the “2024 Notes”) and $350.0 million aggregate principal amount of our 5.600% senior notes due 2044 (the “2044 Notes”), at prices to the public of 99.850%, 99.830% and 99.925%, respectively, of their face value. The 2019 Notes mature on April 1, 2019; the 2024 Notes mature on April 1, 2024; and the 2044 Notes mature on April 1, 2044. The interest payments on the 2019 Notes, 2024 Notes and 2044 Notes are due semi-annually in arrears in April and October.

On November 12, 2014, we issued an additional $100.0 million aggregate principal amount of 2024 Notes and $300.0 million aggregate principal amount of our 5.050% senior notes due 2045 (the “2045 Notes”), at prices to the public of 104.007% and 99.452%, respectively, of their face value. The new 2024 Notes were offered as an additional issue of our outstanding 4.400% Senior Notes due 2024, issued in an aggregate principal amount of $450.0 million on March 19, 2014. The 2024 Notes issued on March 19, 2014 and November 12, 2014 are treated as a single class of debt securities and have identical terms, other than the issue date. The 2045 Notes mature on April 1, 2045, and interest payments on the 2045 Notes are due semi-annually in arrears in April and October.

On May 12, 2015, we issued $900.0 million aggregate principal amount of unsecured senior notes, consisting of $750.0 million aggregate principal amount of our 4.150% senior notes due 2025 (the “2025 Notes”) and an additional $150.0 million aggregate principal amount of 2045 Notes at prices to the public of 99.827% and 96.381%, respectively, of their face value. The 2025 Notes mature on June 1, 2025. Interest payments on the 2025 Notes are due semi-annually in arrears in June and December. The new 2045 Notes were offered as an additional issue of our outstanding 5.050% Senior Notes due 2045, issued in an aggregate principal amount of $300.0 million on November 12, 2014. The 2045 Notes issued on November 12, 2014 and May 12, 2015 are treated as a single class of debt securities and have identical terms, other than the issue date.

On July 14, 2016, we issued $500.0 million in aggregate principal amount of our 4.850% senior notes due 2026 (the “2026 Notes”) at a price to the public of 99.859% of their face value. The 2026 Notes mature on July 15, 2026. Interest payments on the 2026 Notes are due semi-annually in arrears in January and July. Net proceeds of approximately $495.7 million were used to repay outstanding borrowings under our revolving credit facility and for general partnership purposes.

For additional information on outstanding long-term debt issuances, redemption characteristics and criteria, and related debt covenants and indentures, see “Item 8. Financial Statements and Supplementary Data—Note 6.”

Credit Risk

Risks of nonpayment and nonperformance by our customers are a major concern in our business. We are subject to risks of loss resulting from nonpayment or nonperformance by our customers and other counterparties, such as our lenders and hedging counterparties. Any increase in the nonpayment and nonperformance by our customers could adversely affect our results of operations and reduce our ability to make distributions to our unitholders.

Inflation

Inflation in the United States has been relatively low in recent years in the economy as a whole. The midstream natural gas industry’s labor and material costs remained relatively unchanged in 2014, 2015 and 2016. Although the impact of inflation has been insignificant in recent years, it is still a factor in the United States economy and may increase the cost to acquire or replace property, plant and equipment and may increase the costs of labor and supplies. To the extent permitted by competition, regulation and our existing agreements, we have and will continue to pass along increased costs to our customers in the form of higher fees.

Environmental

Our operations are subject to environmental laws and regulations adopted by various governmental authorities in the jurisdictions in which these operations are conducted. We believe we are in material compliance with all applicable laws and regulations. For a more complete discussion of the environmental laws and regulations that impact us, see "Item 1. Business—Environmental Matters."

Contingencies

We are involved in various litigation and administrative proceedings arising in the normal course of business. In the opinion of management, any liabilities that may result from these claims would not individually or in the aggregate have a material adverse effect on its financial position, results of operations or cash flows.

At times, our subsidiaries acquire pipeline easements and other property rights by exercising rights of eminent domain and common carrier. As a result, from time to time, we (or our subsidiaries) are a party to lawsuits under which a court will determine the value of pipeline easements or other property interests obtained by our subsidiaries by condemnation. Damage awards in these suits should reflect the value of the property interest acquired and the diminution in the value of the remaining property owned by the landowner. However, some landowners have alleged unique damage theories to inflate their damage claims or assert valuation methodologies that could result in damage awards in excess of the amounts anticipated. Although it is not possible to predict the ultimate outcomes of these matters, we do not expect that awards in these matters will have a material adverse impact on our consolidated results of operations, financial condition or cash flows.

We (or our subsidiaries) are defending lawsuits filed by owners of property located near processing facilities or compression facilities constructed by us as part of our systems. The suits generally allege that the facilities create a private nuisance and have damaged the value of surrounding property. Claims of this nature have arisen as a result of the industrial development of natural gas gathering, processing and treating facilities in urban and occupied rural areas.

In July 2013, the Board of Commissioners for the Southeast Louisiana Flood Protection Authority for New Orleans and surrounding areas filed a lawsuit against approximately 100 energy companies, seeking, among other relief, restoration of wetlands allegedly lost due to historic industry operations in those areas. The suit was filed in Louisiana state court in New Orleans, but was removed to the United States District Court for the Eastern District of Louisiana. The amount of damages is unspecified. Our subsidiary, EnLink LIG, LLC, is one of the named defendants as the owner of pipelines in the area. On February 13, 2015, the court granted defendants' joint motion to dismiss and dismissed the plaintiff's claims with prejudice. Plaintiffs have appealed the matter to the United States Court of Appeals for the Fifth Circuit. We intend to continue vigorously defending the case. The success of the plaintiffs' appeal as well as our costs and legal exposure, if any, related to the lawsuit are not currently determinable.

We own and operate a high-pressure pipeline and underground natural gas and NGL storage reservoirs and associated facilities near Bayou Corne, Louisiana. In August 2012, a large sinkhole formed in the vicinity of this pipeline and underground storage reservoirs. We are seeking to recover our losses from responsible parties. We have sued Texas Brine Company, the operator of a failed cavern in the area and its insurers, seeking recovery for these losses in in the 23rd Judicial Court, Assumption Parish, Louisiana. We have also sued Occidental Chemical Company and Legacy Vulcan Corp. f/k/a Vulcan Materials Company, two Chlor-Alkali plant operators that participated in Texas Brine's operational decisions regarding mining the failed cavern. We also filed a claim with our insurers, which our insurers denied. We have filed a claim for defense and indemnity with our insurers. In August 2014, we received a partial settlement from Texas Brine's insurers with respect to the Texas Brine claims in the amount of $6.1 million, but additional claims remain outstanding. We cannot give assurance that we will be able to fully recover our losses through insurance recovery or claims against responsible parties.

In June 2014, a group of landowners in Assumption Parish, Louisiana added our subsidiary, EnLink Processing Services, LLC, as a defendant in a pending lawsuit they had filed against Texas Brine, Occidental Chemical Corporation, and Vulcan Materials Company relating to claims arising from the Bayou Corne sinkhole. The suit is pending in the 23rd

Judicial Court, Assumption Parish, Louisiana. Although plaintiffs' claims against the other defendants had been pending since October 2012, plaintiffs alleged in June 2014 and continue to allege that EnLink Processing Services, LLC's negligence also contributed to the formation of the sinkhole. The amount of damages is unspecified. The validity of the causes of action, as well as our costs and legal exposure, if any, related to the lawsuit are not currently determinable. We intend to vigorously defend the case. We have also filed a claim for defense and indemnity with our insurers.

Recent Accounting Pronouncements

See "Item 8. Financial Statements and Supplementary Data—Note 2."

Disclosure Regarding Forward-Looking Statements

This Annual Report on Form 10-K ("Annual Report") contains forward-looking statements that are based on information currently available to management as well as management's assumptions and beliefs. All statements, other than statements of historical fact, included in this Annual Report constitute forward-looking statements, including but not limited to statements identified by the words "forecast," "may," "believe," "will," "should," "plan," "predict," "anticipate," "intend," "estimate" and "expect" and similar expressions. Such statements reflect our current views with respect to future events, based on what we believe are reasonable assumptions; however, such statements are subject to certain risks and uncertainties. In addition to the specific uncertainties discussed elsewhere in this Annual Report, the risk factors set forth in "Item 1A. Risk Factors" may affect our performance and results of operations. Should one or more of these risks or uncertainties materialize, or should underlying assumptions prove incorrect, actual results may differ materially from those in the forward-looking statements. We disclaim any intention or obligation to update or review any forward-looking statements or information, whether as a result of new information, future events or otherwise.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

Market risk is the risk of loss arising from adverse changes in market rates and prices. Our primary market risk is the risk related to changes in the prices of natural gas, NGLs, condensate and crude oil. In addition, we are also exposed to the risk of changes in interest rates on floating rate debt.

Comprehensive financial reform legislation was signed into law by the President on July 21, 2010. The legislation calls for the Commodities Futures Trading Commission ("CFTC") to regulate certain markets for derivative products, including over-the-counter ("OTC") derivatives. The CFTC has issued several new relevant regulations and other rulemakings are pending at the CFTC, the product of which would be rules that implement mandates in new legislation to cause significant portions of derivatives markets to clear through clearinghouses. While some of these rules have been finalized, some have not and, as a result, the final form and timing of the implementation of the new regulatory regime affecting commodity derivatives remains uncertain.

In particular, on October 18, 2011, the CFTC adopted final rules under the Dodd-Frank Act establishing position limits for certain energy commodity futures and options contracts and economically equivalent swaps, futures and options. The position limit levels set the maximum amount of covered contracts that a trader may own or control separately or in combination, net long or short. The final rules also contained limited exemptions from position limits which would be phased in over time for certain bona fide hedging transactions and positions. The CFTC's original position limits rule was challenged in court by two industry associations and was vacated and remanded by a federal district court. However, in November 2013, the CFTC proposed new rules that would place limits on positions in certain core futures and equivalent swaps contracts for or linked to certain physical commodities, subject to exceptions for certain bona fide hedging transactions. The CFTC has sought comment on the position limits rule as reproposed, but these new position limit rules are not yet final and the impact of those provisions on us is uncertain at this time. The CFTC has withdrawn its appeal of the court order vacating the original position limits rule.

The legislation and new regulations may also require counterparties to our derivative instruments to spin off some of their derivatives activities to separate entities, which may not be as creditworthy as the current counterparties. The new legislation and any future new regulations could significantly increase the cost of derivative contracts, materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives 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 to generate sufficient cash flow to pay quarterly distributions at current levels or at all. Our revenues could be adversely affected if a consequence of the legislation and regulations is lower commodity prices. Any of these consequences could have a material, adverse effect on us, our financial condition and our results of operations.

Commodity Price Risk

We are subject to significant risks due to fluctuations in commodity prices. Our exposure to these risks is primarily in the gas processing component of our business. We currently process gas under four main types of contractual arrangements as summarized below. Approximately 88% of our processing margins are from fixed-fee based contracts for the year ended December 31, 2016.

1. *Processing margin contracts:* Under this type of contract, we pay the producer for the full amount of inlet gas to the plant, and we make a margin based on the difference between the value of liquids recovered from the processed natural gas as compared to the value of the natural gas volumes lost and the cost of fuel used in processing. The shrink and fuel losses are referred to as plant thermal reduction, or PTR. Our margins from these contracts are high during periods of high liquids prices relative to natural gas prices and can be negative during periods of high natural gas prices relative to liquids prices. However, we mitigate our risk of processing natural gas when margins are negative primarily through our ability to bypass processing when it is not profitable for us or by contracts that revert to a minimum fee for processing if the natural gas must be processed to meet pipeline quality specifications.

2. *Percent of liquids contracts:* Under these contracts, we receive a fee in the form of a percentage of the liquids recovered, and the producer bears all the cost of the natural gas shrink. Therefore, our margins from these contracts are greater during periods of high liquids prices. Our margins from processing cannot become negative under percent of liquids contracts, but they do decline during periods of low NGL prices.

3. *Percent of proceeds contracts:* Under these contracts, we receive a fee as a portion of the proceeds of the sale of natural gas and liquids. Therefore, our margins from these contracts are greater during periods of high natural gas and liquids prices. Our margins from processing cannot become negative under percent of proceeds contracts, but do decline during periods of low natural gas and NGL prices.

4. *Fixed-fee based contracts:* Under these contracts we have no direct commodity price exposure and are paid a fixed fee per unit of volume that is processed.

Our primary commodity risk management objective is to reduce volatility in our cash flows. We maintain a risk management committee, including members of senior management, which oversees all hedging activity. We enter into hedges for natural gas and NGLs using over-the-counter derivative financial instruments with only certain well-capitalized counterparties which have been approved by our risk management committee.

We have hedged our exposure to fluctuations in prices for natural gas and NGL volumes produced for our account. We hedge our exposure based on volumes we consider hedgeable (volumes committed under contracts that are long term in nature) versus total volumes that include volumes that may fluctuate due to contractual terms, such as contracts with month to month processing options. Further, we have tailored our hedges to generally match the NGL product composition and the NGL and natural gas delivery points to those of our physical equity volumes. The NGL hedges cover specific NGL products based upon our expected equity NGL composition.

The following table sets forth certain information related to derivative instruments outstanding at December 31, 2016 mitigating the risks associated with the gas processing and fractionation components of our business. The relevant payment index price for liquids is the monthly average of the daily closing price for deliveries of commodities into Mont

Belvieu, Texas as reported by OPIS. The relevant index price for Natural Gas is Henry Hub Gas Daily is as defined by the pricing dates in the swap contracts.

Period	Underlying	Notional Volume	We Pay	We Receive (1)	Fair Value Asset/(Liability) (In millions)
January 2017 - December 2017	Ethane	167 (MBbls)	$0.2642/gal (1)	Index	$ 0.2
January 2017 - December 2017	Propane	434 (MBbls)	Index	$0.5461/gal	(2.3)
January 2017 - December 2017	Normal Butane	161 (MBbls)	Index	$0.7048/gal	(1.0)
January 2017 - December 2017	Natural Gasoline	95 (MBbls)	Index	$1.0691/gal	(0.5)
January 2017 - December 2017	Natural Gas	21,685 (MMBtu/d)	Index	$3.1422/MMBtu	(2.7)
					$ (6.3)

(1) weighted average

Another price risk we face is the risk of mismatching volumes of gas bought or sold on a monthly price versus volumes bought or sold on a daily price. We enter each month with a balanced book of natural gas bought and sold on the same basis. However, it is normal to experience fluctuations in the volumes of natural gas bought or sold under either basis, which leaves us with short or long positions that must be covered. We use financial swaps to mitigate the exposure at the time it is created to maintain a balanced position.

The use of financial instruments may expose us to the risk of financial loss in certain circumstances, including instances when (1) sales volumes are less than expected requiring market purchases to meet commitments or (2) counterparties fail to purchase the contracted quantities of natural gas or otherwise fail to perform. To the extent that we engage in hedging activities, we may be prevented from realizing the benefits of favorable price changes in the physical market. However, we are similarly insulated against unfavorable changes in such prices.

As of December 31, 2016, outstanding natural gas swap agreements, NGL swap agreements, swing swap agreements, storage swap agreements and other derivative instruments were a net fair value liability of $6.3 million. The aggregate effect of a hypothetical 10% change, increase or decrease, in gas and NGL prices would result in a change of approximately $3.1 million in the net fair value of these contracts as of December 31, 2016.

Interest Rate Risk

We are exposed to interest rate risk on our variable rate bank credit facility. At December 31, 2016, we had $120.0 million in outstanding borrowings under this facility. A 1% increase or decrease in interest rates would change our annual interest expense by approximately $1.2 million for the year.

We are not exposed to changes in interest rates with respect to our senior unsecured notes due in 2019, 2022, 2024, 2025, 2026, 2044, or 2045 as these are fixed-rate obligations. The estimated fair value of our senior unsecured notes was approximately $3,105.7 million as of December 31, 2016, based on market prices of similar debt at December 31, 2016. Market risk is estimated as the potential decrease in fair value of our long-term debt resulting from a hypothetical increase of 1% in interest rates. Such an increase in interest rates would result in an approximately $229.7 million decrease in fair value of our senior unsecured notes at December 31, 2016.

Item 8. Financial Statements and Supplementary Data

INDEX TO FINANCIAL STATEMENTS

EnLink Midstream Partners, LP Financial Statements:

MANAGEMENT'S REPORT ON

INTERNAL CONTROL OVER FINANCIAL REPORTING

Management of EnLink Energy GP, LLC is responsible for establishing and maintaining adequate internal control over financial reporting and for the assessment of the effectiveness of internal control over financial reporting for EnLink Midstream Partners, LP (the "Partnership"). As defined by the Securities and Exchange Commission (Rule 13a-15(f) under the Securities Exchange Act of 1934, as amended), internal control over financial reporting is a process designed by, or under the supervision of EnLink Energy GP, LLC's principal executive and principal financial officers and effected by its 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 U.S. generally accepted accounting principles.

The Partnership's internal control over financial reporting is supported by written 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 U.S. generally accepted accounting principles, and that receipts and expenditures of the Partnership are being made only in accordance with authorization of the EnLink Energy GP, LLC'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, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In connection with the preparation of the Partnership's annual consolidated financial statements, management has undertaken an assessment of the effectiveness of the Partnership's internal control over financial reporting 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 COSO Framework). Management's assessment included an evaluation of the design of the Partnership's internal control over financial reporting and testing of the operational effectiveness of those controls.

Based on this assessment, management has concluded that as of December 31, 2016, the Partnership's internal control over financial reporting was effective to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with U.S. generally accepted accounting principles.

KPMG LLP, the independent registered public accounting firm that audited the Partnership's consolidated financial statements included in this report, has issued an attestation report on the Partnership's internal control over financial reporting, a copy of which appears on the following page of this Annual Report on Form 10-K.

Report of Independent Registered Public Accounting Firm

The Partners

EnLink Midstream Partners, LP:

We have audited the accompanying consolidated balance sheets of EnLink Midstream Partners, LP (a Delaware limited partnership) and subsidiaries as of December 31, 2016 and 2015, and the related consolidated statements of operations, changes in partners' equity, and cash flows for each of the years in the three-year period ended December 31, 2016. We also have audited EnLink Midstream Partners, LP's internal control over financial reporting 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 (COSO). EnLink Midstream Partners, LP's management is responsible for these consolidated financial statements and 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 consolidated financial statements and an opinion on the Partnership's internal control over financial reporting based on our audits.

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

A company's internal control over financial reporting is a process designed 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 its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of EnLink 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 years in the three-year period ended December 31, 2016, in conformity with U.S. generally accepted accounting principles. Also in our opinion, EnLink Midstream Partners, LP maintained, in all material respects, effective internal control over financial reporting 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.

As discussed in Note 2(h) to the financial statements, effective March 7, 2014, the Partnership has elected to change its method of accounting for computing depreciation under the units-of-production method for certain assets. That change is a change in accounting estimate effected by and inseparable from the change in accounting principle.

/s/ KPMG LLP

Dallas, Texas

February 15, 2017

ENLINK MIDSTREAM PARTNERS, LP
Consolidated Balance Sheets
(In millions, except unit data)

	December 31, 2016	December 31, 2015
ASSETS		
Current assets:		
Cash and cash equivalents	$ 11.6	$ 5.9
Accounts receivable:		
Trade, net of allowance for bad debt of $0.1 and $0.3, respectively	63.9	37.5
Accrued revenue and other	369.6	268.7
Related party	100.2	111.1
Fair value of derivative assets	1.3	16.8
Natural gas and NGLs inventory, prepaid expenses and other	31.0	32.1
Investments in unconsolidated affiliates - current	193.1	—
Total current assets	770.7	472.1
Property and equipment, net of accumulated depreciation of $2,124.1 and $1,757.6, respectively	6,256.7	5,666.8
Intangible assets, net of accumulated amortization of $171.6 and $54.6, respectively	1,624.2	689.9
Goodwill	422.3	987.0
Investments in unconsolidated affiliates - non current	77.3	274.3
Other assets, net	2.2	2.7
Total assets	$ 9,153.4	$ 8,092.8
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities:		
Accounts payable and drafts payable	$ 69.2	$ 33.2
Accounts payable to related party	10.4	14.8
Accrued gas, NGLs, condensate and crude oil purchases	333.3	206.7
Fair value of derivative liabilities	7.6	2.9
Installment payable, net of discount of $0.5	249.5	—
Other current liabilities	217.0	174.4
Total current liabilities	887.0	432.0
Long-term debt	3,268.0	3,066.8
Fair value of derivative liabilities	—	0.1
Asset retirement obligations	13.5	12.9
Installment payable, net of discount of $26.3	223.7	—
Other long-term liabilities	42.6	65.9
Deferred tax liability	73.0	73.6
Redeemable non-controlling interest	5.2	7.0
Partners' equity:		
Common unitholders (342,856,292 and 325,090,624 units issued and outstanding at December 31, 2016 and December 31, 2015, respectively)	3,193.2	4,055.8
Class C unitholders (7,075,433 units issued and outstanding at December 31, 2015)	—	149.4
Preferred unitholders (53,182,651 units issued and outstanding at December 31, 2016)	794.0	—
General partner interest (1,594,974 equivalent units outstanding at December 31, 2016 and December 31, 2015)	209.1	213.4
Non-controlling interest	444.1	15.9
Total partners' equity	4,640.4	4,434.5
Commitments and contingencies (Note 14)		
Total liabilities and partners' equity	$ 9,153.4	$ 8,092.8

See accompanying notes to consolidated financial statements.

ENLINK MIDSTREAM PARTNERS, LP
Consolidated Statements of Operations
(In millions, except per unit data)

	Year Ended December 31,		
	2016	2015	2014
Revenues:			
Product sales	$ 3,008.9	$ 3,253.7	$ 2,159.3
Product sales - related parties	134.3	119.4	505.6
Midstream services	467.2	451.0	253.4
Midstream services - related parties	653.1	618.6	567.4
Gain (loss) on derivative activity	(11.1)	9.4	22.1
Total revenues	4,252.4	4,452.1	3,507.8
Operating costs and expenses:			
Cost of sales (1)	3,015.5	3,245.3	2,494.5
Operating expenses (2)	398.5	419.9	283.6
General and administrative (3)	119.3	132.4	94.5
(Gain) loss on disposition of assets	13.2	1.2	(0.1)
Depreciation and amortization	503.9	387.3	284.3
Impairments	566.3	1,563.4	—
Gain on litigation settlement	—	—	(6.1)
Total operating costs and expenses	4,616.7	5,749.5	3,150.7
Operating income (loss)	(364.3)	(1,297.4)	357.1
Other income (expense):			
Interest expense, net of interest income	(188.1)	(102.5)	(47.4)
Income (loss) from unconsolidated affiliates	(19.9)	20.4	18.9
Gain on extinguishment of debt	—	—	3.2
Other income (expense)	0.3	0.8	(0.5)
Total other expense	(207.7)	(81.3)	(25.8)
Income (loss) from continuing operations before non-controlling interest and income taxes	(572.0)	(1,378.7)	331.3
Income tax benefit (provision)	(1.3)	0.5	(22.0)
Net income (loss) from continuing operations	(573.3)	(1,378.2)	309.3
Income from discontinued operations, net of tax	—	—	1.0
Net income (loss)	(573.3)	(1,378.2)	310.3
Net loss attributable to the non-controlling interest	(8.1)	(0.4)	(0.2)
Net income (loss) attributable to EnLink Midstream Partners, LP	$ (565.2)	$ (1,377.8)	$ 310.5
Predecessor interest in net income (4)	$ —	$ —	$ 35.5
General partner interest in net income	$ 39.5	$ 58.0	$ 138.3
Limited partners' interest in net income (loss) attributable to EnLink Midstream Partners, LP	$ (662.1)	$ (1,405.2)	$ 136.7
Class C partners' interest in net loss attributable to EnLink Midstream Partners, LP	$ (12.5)	$ (30.6)	$ —
Preferred interest in net income attributable to EnLink Midstream Partners, LP	$ 69.9	$ —	$ —
Net income (loss) attributable to EnLink Midstream Partners, LP per limited partners' unit:			
Basic common unit	$ (1.99)	$ (4.66)	$ 0.59
Diluted common unit	$ (1.99)	$ (4.66)	$ 0.59

(1) Includes related party cost of sales of $150.1 million, $141.3 million and $354.3 million for the years ended December 31, 2016, 2015 and 2014, respectively.
(2) Includes related party operating expenses of $0.5 million, $0.5 million and $5.9 million for the years ended December 31, 2016, 2015 and 2014, respectively.
(3) Includes related party general and administrative expenses of $0.0 million, $0.2 million and $11.6 million for the years ended December 31, 2016, 2015 and 2014, respectively.
(4) Represents net income attributable to the Predecessor for the period prior to March 7, 2014.

See accompanying notes to consolidated financial statements

ENLINK MIDSTREAM PARTNERS, LP
Consolidated Statements of Changes in Partners' Equity
Year Ended December 31, 2016, 2015 and 2014
(In millions)

	Common Units		Class C Common Units		Preferred Units		General Partner Interest		Predecessor Equity	Non-Controlling Interest		Redeemable Non-controlling interest (Temporary Equity)
	$	Units	$	Units	$	Units	$	Units	$	$	Total	$
Balance, December 31, 2013	$ —	—	$ —	—	$ —	—	$ —	—	$ 1,783.7	$ —	$ 1,783.7	$ —
Distributions to the Predecessor	—	—	—	—	—	—	—	—	(71.9)	—	(71.9)	—
Elimination of deferred taxes due to reorganization of predecessor	—	—	—	—	—	—	—	—	444.5	—	444.5	—
Issuance of units for reorganization of predecessor equity	1,095.9	120.5	—	—	—	—	—	—	(2,191.8)	1,095.9	—	—
Issuance of common units for acquisition of Partnership	3,329.6	109.1	—	—	—	—	48.7	1.6	—	—	3,378.3	—
Issuance of common units	412.0	14.6	—	—	—	—	—	—	—	—	412.0	—
Acquisition of interest in joint venture	31.0	1.0	—	—	—	—	—	—	—	7.2	38.2	—
Proceeds from exercise of unit options	0.4	0.1	—	—	—	—	—	—	—	—	0.4	—
Conversion of restricted units for common units, net of units withheld for taxes	(0.7)	0.1	—	—	—	—	—	—	—	—	(0.7)	—
Unit-based compensation	9.0	—	—	—	—	—	10.4	—	—	—	19.4	—
Distributions	(222.7)	—	—	—	—	—	(17.1)	—	—	—	(239.8)	—
Distributions to non-controlling interest	—	—	—	—	—	—	—	—	—	(159.5)	(159.5)	—
Non-controlling interest contributions	—	—	—	—	—	—	—	—	—	5.3	5.3	—
Acquisition of interest in Midstream Holdings (Note 3)	936.4	—	—	—	—	—	—	—	—	(936.4)	—	—
Acquisition of VEX Interests (Note 3)	105.7	—	—	—	—	—	—	—	—	—	105.7	—
Net income (loss)	136.7	—	—	—	—	—	138.3	—	35.5	(0.2)	310.3	—
Balance, December 31, 2014	$ 5,833.3	245.4	$ —	—	$ —	—	$ 180.3	1.6	$ —	$ 12.3	$ 6,025.9	$ —
Issuance of common units	204.3	76.8	180.0	6.7	—	—	—	—	—	—	384.3	—
Issuance of common units to ENLC	50.0	2.8	—	—	—	—	—	—	—	—	50.0	—
Conversion of restricted units for common units, net of units withheld for taxes	(2.5)	0.2	—	—	—	—	—	—	—	—	(2.5)	—
Unit-based compensation	17.4	—	—	—	—	—	18.3	—	—	—	35.7	—
Contribution from Devon	27.8	—	—	—	—	—	—	—	—	—	27.8	—
Distribution attributable to VEX interests transferred (Note 3)	(166.7)	—	—	—	—	—	—	—	—	—	(166.7)	—
Distributions	(436.1)	—	—	0.4	—	—	(43.2)	—	—	—	(479.3)	—
Non-controlling interest contributions	—	—	—	—	—	—	—	—	—	16.4	16.4	—
Distributions to non-controlling interest	—	—	—	—	—	—	—	—	—	(66.5)	(66.5)	—
Adjustment related to mandatory redemption of E2 non-controlling interest	—	—	—	—	—	—	—	—	—	(5.4)	(5.4)	—
Redeemable non-controlling interest	—	—	—	—	—	—	—	—	—	(7.0)	(7.0)	7.0
Transfer of interest in Midstream Holdings (Notes 3)	(66.5)	—	—	—	—	—	—	—	—	66.5	—	—
Net income (loss)	(1,405.2)	—	(30.6)	—	—	—	58.0	—	—	(0.4)	(1,378.2)	—
Balance, December 31, 2015	$ 4,055.8	325.2	$ 149.4	7.1	$ —	—	$ 213.4	1.6	$ —	$ 15.9	$ 4,434.5	$ 7.0

	Common Units		Class C Common Units		Preferred Units		General Partner Interest		Predecessor Equity	Non-Controlling Interest		Redeemable Non-controlling interest (Temporary Equity)
	$	Units	$	Units	$	Units	$	Units	$	$	Total	$
Issuance of common units	167.5	10.0	—	—	—	—	—	—	—	—	167.5	—
Issuance of Preferred Units	—	—	—	—	724.1	50.0	—	—	—	—	724.1	—
Contribution from ENLC	—	—	—	—	—	—	—	—	—	237.1	237.1	—
Conversion of restricted units for common units, net of units withheld for taxes	(1.2)	0.2	—	—	—	—	—	—	—	—	(1.2)	—
Unit-based compensation	15.1	—	—	—	—	—	14.9	—	—	—	30.0	—
Contribution from Devon	1.5	—	—	—	—	—	—	—	—	—	1.5	—
Distributions	(520.3)	—	—	0.4	—	3.2	(58.7)	—	—	—	(579.0)	—
Conversion of Class C Common Units to common units	136.9	7.5	(136.9)	(7.5)	—	—	—	—		—	—	—
Non-controlling interest contributions	—	—	—	—	—	—	—	—	—	207.4	207.4	—
Distributions to non-controlling interest	—	—	—	—	—	—	—	—	—	(8.2)	(8.2)	—
Distributions to Redeemable non-controlling interest	—	—	—	—	—	—	—	—	—	—	—	(1.8)
Net income (loss)	(662.1)	—	(12.5)	—	69.9	—	39.5	—	—	(8.1)	(573.3)	—
Balance, December 31, 2016	$ 3,193.2	342.9	$ —	—	$ 794.0	53.2	$ 209.1	1.6	$ —	$ 444.1	$ 4,640.4	$ 5.2

See accompanying notes to consolidated financial statements.

ENLINK MIDSTREAM PARTNERS, LP
Consolidated Statements of Cash Flows
(In millions)

	Year Ended December 31,		
	2016	2015	2014
Cash flows from operating activities:			
Net income (loss) from continuing operations	$ (573.3)	$ (1,378.2)	$ 309.3
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation and amortization	503.9	387.3	284.3
Impairments	566.3	1,563.4	—
Accretion expense	0.6	0.6	0.5
(Gain) loss on disposition of assets	13.2	1.2	(0.1)
Non-cash unit-based compensation	30.0	35.7	19.4
Gain on extinguishment of debt	—	—	(3.2)
Deferred tax expense (benefit)	(0.6)	(3.6)	15.3
(Gain) loss on derivatives recognized in net income (loss)	11.1	(9.4)	(22.1)
Cash settlements on derivatives	10.5	17.1	(0.3)
Amortization of debt issue costs	3.6	3.1	1.7
Amortization of net (premium) discount on notes	49.5	(2.9)	(2.9)
Redeemable non-controlling interest expense	0.3	(1.8)	—
Distribution of earnings from unconsolidated affiliates	3.1	21.6	7.0
(Income) loss from unconsolidated affiliates	19.9	(20.4)	(18.9)
Changes in assets and liabilities net of assets acquired and liabilities assumed:			
Accounts receivable, accrued revenue and other	(117.9)	197.4	(85.4)
Natural gas and NGLs inventory, prepaid expenses and other	10.2	4.2	(6.9)
Accounts payable, accrued gas and crude oil purchases and other accrued liabilities	132.2	(169.7)	(18.3)
Net cash provided by operating activities	662.6	645.6	479.4
Cash flows from investing activities, net of assets acquired and liabilities assumed:			
Additions to property and equipment	(663.0)	(572.3)	(796.0)
Acquisition of business, net of cash acquired	(769.3)	(524.2)	(421.1)
Proceeds from insurance settlement	0.3	2.9	—
Proceeds from sale of property	93.1	1.0	0.1
Investment in unconsolidated affiliates	(73.8)	(25.8)	(5.7)
Distribution from unconsolidated affiliates in excess of earnings	54.6	21.1	10.9
Net cash used in investing activities	(1,358.1)	(1,097.3)	(1,211.8)
Cash flows from financing activities:			
Proceeds from borrowings	2,057.8	3,204.4	3,151.5
Payments on borrowings	(1,852.7)	(2,134.3)	(2,501.3)
Payments on capital lease obligations	(6.6)	(3.6)	(3.0)
Increase (decrease) in drafts payable	—	(12.7)	10.2
Debt refinancing costs	(4.6)	(9.5)	(18.5)
Conversion of restricted units, net of units withheld for taxes	(1.2)	(2.5)	(0.7)
Proceeds from issuance of common units to general partner	—	50.0	—
Proceeds from issuance of common units	167.5	24.4	412.0
Proceeds from issuance of Preferred Units	724.1	—	—
Distributions to non-controlling partners	(10.0)	(66.5)	(159.5)
Contributions by non-controlling partners (including affiliate contributions of $39.5 million for the year ended December 31, 2016)	207.4	16.4	6.3
Distribution to partners	(579.0)	(479.3)	(239.8)
Redeemable non-controlling interest	(3.0)	—	—
Distributions to Predecessor	—	—	(21.3)
Contribution from Devon	1.5	27.8	105.7
Proceeds from exercise of unit options	—	0.1	0.4
Distributions to Devon for net assets acquired	—	(166.7)	—
Net cash provided by financing activities	701.2	448.0	742.0
Cash flow from discontinued operations:			
Net cash provided by operating activities	—	—	5.0
Net cash provided by (used in) investing activities	—	—	(0.6)
Net cash used in financing activities-net distributions to Devon and non-controlling interests	—	—	(4.4)
Net cash provided by discontinued operations	—	—	—
Net increase (decrease) in cash and cash equivalents	5.7	(3.7)	9.6
Cash and cash equivalents, beginning of year	5.9	9.6	—
Cash and cash equivalents, end of year	$ 11.6	$ 5.9	$ 9.6
Cash paid for interest	$ 132.5	$ 109.4	$ 53.8
Cash paid for income taxes	$ 2.8	$ 0.5	$ 7.1

See accompanying notes to consolidated financial statements.

ENLINK MIDSTREAM PARTNERS, LP
Notes to Consolidated Financial Statements

(1) Organization and Summary of Significant Agreements

(a) Organization of Business and Nature of Business

EnLink Midstream Partners, LP is a publicly traded Delaware limited partnership formed in 2002. Our common units are traded on the New York Stock Exchange under the symbol "ENLK." Our business activities are conducted through our subsidiary, EnLink Midstream Operating, LP, a Delaware limited partnership (the "Operating Partnership"), and the subsidiaries of the Operating Partnership.

EnLink Midstream GP, LLC, a Delaware limited liability company, is our general partner. Our general partner manages our operations and activities. Our general partner is an indirect wholly-owned subsidiary of EnLink Midstream, LLC ("ENLC"). ENLC's units are traded on the New York Stock Exchange under the symbol "ENLC." Devon Energy Corporation ("Devon") owns ENLC's managing member and common units, which represent approximately 64% of the outstanding limited liability company interests in ENLC as of December 31, 2016.

Effective as of March 7, 2014, the Operating Partnership acquired (the "Acquisition") 50% of the outstanding equity interests in EnLink Midstream Holdings, LP ("Midstream Holdings") and all of the outstanding equity interests in EnLink Midstream Holdings GP, LLC, the general partner of Midstream Holdings, in exchange for the issuance by us of 120,542,441 units of our limited partnership interests. At the same time, EnLink Midstream, Inc. ("EMI"), the entity that directly owns our general partner, became a wholly-owned subsidiary of ENLC (together with the Acquisition, the "Business Combination"). ENLC, through another wholly-owned subsidiary, owned the remaining 50% of the outstanding equity interests in Midstream Holdings.

On February 17, 2015, ENLC's wholly-owned subsidiary contributed a 25% interest in Midstream Holdings (the "February 2015 Transferred Interests") to us in a drop down transaction (the "February 2015 EMH Drop Down") in exchange for 31,618,311 of our Class D Common Units. On May 27, 2015, ENLC's subsidiary contributed the remaining 25% limited partner interest in Midstream Holdings (the "May 2015 Transferred Interests") to us in a drop down transaction (the "May 2015 EMH Drop Down" and together with the February 2015 EMH Drop Down, the "EMH Drop Downs") in exchange for 36,629,888 of our Class E Common Units. After giving effect to the EMH Drop Downs, we own 100% of Midstream Holdings. In addition, on April 1, 2015, we acquired the Victoria Express Pipeline and related truck terminal and storage assets from Devon (the "VEX Interests").

Effective as of January 7, 2016, the Operating Partnership acquired 84% of the outstanding equity interests in EnLink Oklahoma T.O., and ENLC acquired the remaining 16% equity interests in EnLink Oklahoma T.O. Since we control EnLink Oklahoma T.O., we reflect our ownership in EnLink Oklahoma T.O. on a consolidated basis, and ENLC's ownership is reflected as a non-controlling interest in the respective consolidated financial statements and related disclosures. See "Note 3—Acquisitions" for further discussion.

On August 1, 2016, we formed a joint venture (the "Delaware Basin JV") with an affiliate of NGP Natural Resources XI, L.P. ("NGP") to operate and expand our natural gas, natural gas liquids ("NGLs") and crude oil midstream assets in the liquids-rich Delaware Basin. The Delaware Basin JV is owned 50.1% by us and 49.9% by NGP. Since we control the Delaware Basin JV, we reflect our ownership in the Delaware Basin JV on a consolidated basis, and NGP's ownership is reflected as a non-controlling interest in the consolidated financial statements and related disclosures. See "Note 3—Acquisitions" for further discussion.

(b) Nature of Business

We primarily focus on providing midstream energy services, including gathering, transmission, processing, fractionation, storage, condensate stabilization, brine services and marketing to producers of natural gas, NGLs, crude oil and condensate. We connect the wells of producers in our market areas to our gathering systems, process natural gas to remove NGLs, fractionate NGLs into purity products and market those products for a fee, transport natural gas and ultimately provide natural gas to a variety of markets. We purchase natural gas from natural gas producers and other supply sources and sell that natural gas to utilities, industrial consumers, other marketers and pipelines. We operate processing plants that process gas transported to the plants by major interstate pipelines or from our own gathering systems under a variety of fee-based arrangements. We provide a variety of crude oil and condensate services, which include crude oil and condensate gathering and transmission via pipelines, barges, rail and trucks, condensate stabilization and brine disposal. We also have crude oil and condensate terminal facilities that provide access for crude oil and condensate producers to premium markets. Our gas gathering systems consist of networks of pipelines that collect natural gas from points near producing wells and transport it to larger pipelines for further transmission. Our transmission pipelines primarily receive natural gas from our gathering systems and from third party gathering and transmission systems and deliver natural gas to industrial end-users, utilities and other pipelines. We also have transmission lines that transport NGLs from east Texas and from our south Louisiana processing plants to our fractionators in south Louisiana. Our crude oil and condensate gathering and transmission systems consist of trucking facilities, pipelines, rail and barge facilities that, in exchange for a fee, transport crude oil from a producer site to end users and other pipelines. Our processing plants remove NGLs and CO_2 from a natural gas stream, and our fractionators separate the NGLs into separate NGL products, including ethane, propane, iso-butane, normal butane and natural gasoline.

(2) Significant Accounting Policies

(a) Basis of Presentation

The accompanying consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America (“US GAAP”). Further, the consolidated financial statements give effect to the Business Combination under the acquisition method of accounting and are treated as a reverse acquisition. Under the acquisition method of accounting, Midstream Holdings was the accounting acquirer in the transactions because its parent company, Devon, obtained control of us through the indirect control of the general partner as a result of the Business Combination. Consequently, Midstream Holdings’ assets and liabilities retained their carrying values. All financial results prior to March 7, 2014 reflect the historical operations of Midstream Holdings and its majority-owned subsidiaries and are reflected as “Predecessor interest in net income” on the statement of operations for the year ended December 31, 2014. Additionally, our assets acquired and liabilities assumed by Midstream Holdings in the Business Combination were recorded at their fair values measured as of the acquisition date, March 7, 2014. The excess of the purchase price over the estimated fair values of our net assets acquired was recorded as goodwill. Financial results subsequent to March 7, 2014 reflect the combined operations of Midstream Holdings, us and their majority-owned subsidiaries, which give effect to new contracts entered into with Devon and include the legacy Partnership assets. All significant intercompany transactions and balances have been eliminated. Certain assets were not contributed to Midstream Holdings from the Predecessor and the operations of such non contributed assets have been presented as discontinued operations. In conjunction with the Business Combination, Midstream Holdings became a non-taxable entity which was treated as a reorganization under common control with the removal of historical deferred taxes reflected through equity.

During the fourth quarter of 2014 and the first half of 2015, we acquired assets from ENLC and Devon through drop down transactions. Due to ENLC’s control of us through its ownership and control of the general partner and Devon’s control of us through its ownership of the managing member of ENLC, each acquisition from ENLC and Devon was considered a transfer of net assets between entities under common control. As such, we were required to recast our historical financial statements to include the activities of such assets from the date that these entities were under common control. The consolidated financial statements for periods prior to our acquisition of the assets from ENLC and Devon have been prepared from ENLC’s and Devon’s historical cost-basis accounts for the acquired assets and may not necessarily be indicative of the actual results of operations that would have occurred if we had owned the acquired assets during the periods reported. Net income attributable to the assets acquired from ENLC and Devon for periods prior to our acquisition is allocated to the general partner.

(b) Management’s Use of Estimates

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

(c) Revenue Recognition

We generate the majority of our revenues from midstream energy services, including gathering, transmission, processing, fractionation, storage, condensate stabilization, brine services and marketing, through various contractual arrangements, which include fee-based contract arrangements or arrangements where we purchase and resell commodities in connection with providing the related service and earn a net margin for our fee. While our transactions vary in form, the essential element of each transaction is the use of our assets to transport a product or provide a processed product to an end-user at the tailgate of the plant, barge terminal or pipeline. We reflect revenue as Product sales and Midstream services revenue on the consolidated statements of operations as follows:

- *Product sales* - Product sales represent the sale of natural gas, NGLs, crude oil and condensate where the product is purchased and resold in connection with providing our midstream services as outlined above.

- *Midstream services* - Midstream services represents all other revenue generated as a result of performing our midstream services outlined above.

We recognize revenue for sales or services at the time the natural gas, NGLs, crude oil or condensate are delivered or at the time the service is performed at a fixed or determinable price. We generally accrue one month of sales and the related natural gas, NGL, condensate and crude oil purchases and reverse these accruals when the sales and purchases are actually invoiced and recorded in the subsequent month. Actual results could differ from the accrual estimates. Except for fixed-fee based arrangements, we act as the principal in these purchase and sale transactions, bearing the risk and reward of ownership as evidenced by title transfer, scheduling the transportation of products and assuming credit risk. We account for taxes collected from customers attributable to revenue transactions and remitted to government authorities on a net basis (excluded from revenues).

Certain gathering and processing agreements in our Texas, Oklahoma, and Crude and Condensate segments provide for a quarterly or annual minimum volume commitment ("MVC"). Under these agreements, our customers agree to ship and/or process a minimum volume of production on our systems over an agreed time period. If a customer under such an agreement fails to meet its MVC for a specified period, the customer is obligated to pay a contractually-determined fee based upon the shortfall between actual production volumes and the MVC for that period. Some of these agreements also contain make-up right provisions that allow a customer to utilize gathering or processing fees in excess of the MVC in subsequent periods to offset shortfall amounts in previous periods. We record revenue under MVC contracts during periods of shortfall when it is known that the customer cannot, or will not, make up the deficiency in the specified period.

Revenue recorded for the shortfall between actual production volumes and the MVC are as follows (in millions):

	Texas	Oklahoma	Crude and Condensate	Total
Year Ended December 31, 2016				
Midstream services	$ 1.9	$ 9.5	$ —	$ 11.4
Midstream services - related parties	26.4	10.8	9.0	46.2
Total	$ 28.3	$ 20.3	$ 9.0	$ 57.6
Year Ended December 31, 2015				
Midstream services	$ 0.5	$ —	$ —	$ 0.5
Midstream services - related parties	3.8	20.1	0.5	24.4
Total	$ 4.3	$ 20.1	$ 0.5	$ 24.9

(d) Gas Imbalance Accounting

Quantities of natural gas and NGLs over-delivered or under-delivered related to imbalance agreements are recorded monthly as receivables or payables using weighted average prices at the time of the imbalance. These imbalances are typically settled with deliveries of natural gas or NGLs. We had imbalance payables of $7.1 million and $2.6 million at December 31, 2016 and 2015, respectively, which approximate the fair value of these imbalances. We had imbalance receivables of $3.9 million and $3.6 million at December 31, 2016 and 2015, respectively, which are carried at the lower of cost or market value. Imbalance receivables and imbalance payables are included in the line items “Accrued revenue and other” and “Accrued gas, NGLs, condensate and crude oil purchases,” respectively, on the consolidated balance sheets.

(e) Cash and Cash Equivalents

We consider all highly liquid investments with an original maturity of three months or less to be cash equivalents.

(f) Income Taxes

Certain of our operations are subject to income taxes assessed by the federal and various state jurisdictions in the U.S. Additionally, certain of our operations are subject to tax assessed by the state of Texas that is computed based on modified gross margin as defined by the State of Texas. The Texas franchise tax is presented as income tax expense in the accompanying statements of operations. The Predecessor’s operations prior to the merger on March 7, 2014 were subject to income taxes assessed by federal and various state jurisdictions.

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 tax consequences attributable to differences between the financial statement carrying amounts of assets and liabilities and their respective tax bases. Deferred tax assets are also recognized for the future tax benefits attributable to the expected utilization of existing tax net operating loss carryforwards and other types of carryforwards. If the future utilization of some portion of carryforwards is determined to be unlikely, a valuation allowance is provided to reduce the recorded tax benefits from such assets. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences and carryforwards are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date. In the event interest or penalties are incurred with respect to income tax matters, our policy will be to include such items in income tax expense.

(g) Natural Gas, Natural Gas Liquids, Crude Oil and Condensate Inventory

Our inventories of products consist of natural gas, NGLs, crude oil and condensate. We report these assets at the lower of cost or market value which is determined by using the first-in, first-out method.

(h) Property, Plant, and Equipment

Property, plant and equipment are stated at historical cost less accumulated depreciation. Assets acquired in a business combination are recorded at fair value, including our assets acquired by the Predecessor in the Business Combination. Repairs and maintenance are charged against income when incurred. Renewals and betterments, which extend the useful life of the properties, are capitalized. Subsequent to a business combination, interest costs for material projects are capitalized to property, plant and equipment during the period the assets are undergoing preparation for intended use.

ENLINK MIDSTREAM PARTNERS, LP
Notes to Consolidated Financial Statements (Continued)

The components of property, plant and equipment are as follows (in millions):

	December 31, 2016	December 31, 2015
Transmission assets	$ 1,191.7	$ 1,285.1
Gathering systems	3,530.9	2,999.2
Gas processing plants	3,163.0	2,673.7
Other property and equipment	149.5	135.9
Construction in process	345.7	330.5
Property, plant and equipment	8,380.8	7,424.4
Accumulated depreciation	(2,124.1)	(1,757.6)
Property, plant and equipment, net	$ 6,256.7	$ 5,666.8

Change in Depreciation Method. Historically, Midstream Holdings depreciated certain property, plant, and equipment using the units-of-production method. As a result of the Business Combination, we are operated as an independent midstream company and thus no longer have access to Devon's proprietary reserve and production data historically used to compute depreciation under the units-of-production method. Additionally, the existing contracts with Devon were revised to a fee-based arrangement with MVCs. Effective March 7, 2014, we changed our method of computing depreciation for these assets to the straight-line method, consistent with the depreciation method applied to our acquired assets. In accordance with ASC 250, *Accounting Changes and Error Corrections*, we determined that the change in depreciation method was a change in accounting estimate effected by a change in accounting principle, and accordingly, the straight-line method was applied on a prospective basis. This change is considered preferable because the straight-line method will more accurately reflect the pattern of usage and the expected benefits of such assets. The effect of this change in estimate resulted in a decrease in depreciation expense of approximately $29.4 million, or $0.12 per unit for the year ended December 31, 2014.

Depreciation is calculated using the straight-line method based on the estimated useful life of each asset, as follows:

	Useful Lives
Transmission assets	20 - 25 years
Gathering systems	20 - 25 years
Gas processing plants	20 - 25 years
Other property and equipment	3 - 15 years

Depreciation expense of $386.9 million, $331.3 million and $247.8 million was recorded for the years ended December 31, 2016, 2015 and 2014, respectively.

Gain or Loss on Disposition. Upon the disposition or retirement of property, plant and equipment related to continuing operations, any gain or loss is recognized in operating income in the statement of operations. When a disposition or retirement occurs which qualifies as discontinued operations, any gain or loss is recognized as income or loss from discontinued operations in the statement of operations. For the year ended December 31, 2016, we retired or sold net property, plant and equipment of $106.6 million, which was offset by $0.3 million of nonrefundable cash proceeds collected from our insurance carrier and $93.1 million of proceeds from the sale of property. This resulted in a loss on disposition of assets of $13.2 million, which primarily relates to the sale of the North Texas Pipeline System ("NPTL"), a 140-mile natural gas transportation pipeline. We received net proceeds of $84.6 million and recorded a loss on sale of $13.4 million.

For the year ended December 31, 2015, we retired net property, plant and equipment of $5.1 million, which was offset by $2.9 million of nonrefundable cash proceeds collected from our insurance carrier and $1.0 million of proceeds from the sale of property. This resulted in a loss on disposition of assets of $1.2 million, which primarily relates to the retirement of a compressor due to fire damage. Additionally, we collected $2.4 million of business interruption proceeds from our insurance carrier that was presented in the Midstream services revenue line item in the consolidated statement of operations for the year ended December 31, 2015.

ENLINK MIDSTREAM PARTNERS, LP
Notes to Consolidated Financial Statements (Continued)

Impairment Review. We evaluate our property, plant and equipment for potential impairment whenever events or changes in circumstances indicate that the carrying amount of the assets may not be recoverable. The carrying amount of a long-lived asset is not recoverable when it exceeds the undiscounted sum of the future cash flows expected to result from the use and eventual disposition of the asset. Estimates of expected future cash flows represent management's best estimate based on reasonable and supportable assumptions. When the carrying amount of a long-lived asset is not recoverable, an impairment loss is recognized equal to the excess of the asset's carrying value over its fair value. The fair values of long-lived assets are generally determined from estimated discounted future net cash flows. Our estimate of cash flows is based on assumptions, which include: (1) the future fee-based rate of new business or contract renewals; (2) the purchase and resale margins on natural gas, NGLs, condensate and crude oil; (3) the volume of natural gas, NGL, condensate and crude oil available to the asset; (4) markets available to the asset; (5) operating expenses; and (6) future natural gas, crude oil, condensate and NGL product prices. The volume of available natural gas, condensate, NGLs and crude oil to an asset is sometimes based on assumptions regarding future drilling activity, which may be dependent in part on natural gas, NGL, condensate and crude oil prices. Projections of volumes and future commodity prices are inherently subjective and contingent upon a number of variable factors. Any significant variance in any of the above assumptions or factors could materially affect our cash flows, which could require us to record an impairment of an asset. During the year ended December 31, 2015, we recognized a $12.1 million impairment on property, plant and equipment, primarily related to costs associated with the cancellation of various capital projects in our Texas, Louisiana, and Crude and Condensate segments.

(i) Equity Method of Accounting

We account for investments where we do not control the investment but have the ability to exercise significant influence using the equity method of accounting. Under this method, unconsolidated affiliate investments are initially carried at the acquisition cost, increased by our proportionate share of the investee's net income and by contributions made, and decreased by our proportionate share of the investee's net losses and by distributions received.

We evaluate our unconsolidated affiliate investments for potential impairment whenever events or changes in circumstances indicate that the carrying amount of the investments may not be recoverable. We recognize impairments of our investments as a loss from unconsolidated affiliates on our consolidated statements of operations. For additional information, see "Note 10—Investments in Unconsolidated Affiliates."

(j) Goodwill

Goodwill is the cost of an acquisition less the fair value of the net identifiable assets of the acquired business. We evaluate goodwill for impairment annually as of October 31 and whenever events or changes in circumstances indicate it is more likely than not that the fair value of a reporting unit is less than its carrying amount. We first assess qualitative factors to evaluate whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount as the basis for determining whether it is necessary to perform the two-step goodwill impairment test. We may elect to perform the two-step goodwill impairment test without completing a qualitative assessment. If a two-step goodwill impairment test is elected or required, the first step involves comparing the fair value of the reporting unit with its carrying amount. If the carrying amount of a reporting unit exceeds its fair value, the second step of the process involves comparing the implied fair value of goodwill to the carrying value of the goodwill for that reporting unit. If the carrying value of the goodwill of a reporting unit exceeds the implied fair value of that goodwill, the excess of the carrying value over the implied fair value is recognized as an impairment loss. During the year ended December 31, 2016, we recognized a goodwill impairment loss totaling $566.3 million for our Texas and Crude and Condensate segments. During the year ended December 31, 2015, we recognized a goodwill impairment of $1,328.2 million related to our Louisiana, Texas, and Crude and Condensate segments. See "Note 4—Goodwill and Intangible Assets" for further discussion regarding the goodwill impairments.

(k) Intangible Assets

Intangible assets associated with customer relationships are amortized on a straight-line basis over the expected period of benefits of the customer relationships, which range from ten to twenty years.

(l) Asset Retirement Obligations

We recognize liabilities for retirement obligations associated with our pipelines and processing and fractionation facilities. Such liabilities are recognized when there is a legal obligation associated with the retirement of the assets and the amount can be reasonably estimated. The initial measurement of an asset retirement obligation is recorded as a liability at its fair value, with an offsetting asset retirement cost recorded as an increase to the associated property, plant and equipment. If the fair value of a recorded asset retirement obligation changes, a revision is recorded to both the asset retirement obligation and the asset retirement cost. Our retirement obligations include estimated environmental remediation costs that arise from normal operations and are associated with the retirement of the long-lived assets. The asset retirement cost is depreciated using the straight-line depreciation method similar to that used for the associated property, plant and equipment.

(m) Other Long-Term Liabilities

Other current and long-term liabilities include a liability related to an onerous performance obligation assumed in the Business Combination of $44.8 million and $62.8 million as of December 31, 2016 and 2015, respectively. We have one delivery contract that requires us to deliver a specified volume of gas each month at an indexed base price with a term to 2019. We realize a loss on the delivery of gas under this contract each month based on current prices. The fair value of this onerous performance obligation was recorded as a result of the March 7, 2014 Business Combination and was based on forecasted discounted cash obligations in excess of market under this gas delivery contract. The liability is reduced each month as delivery is made over the remaining life of the contract with an offsetting reduction in purchased gas costs.

(n) Derivatives

We use derivative instruments to hedge against changes in cash flows related to product price only. We generally determine the fair value of swap contracts based on the difference between the derivative's fixed contract price and the underlying market price at the determination date. The asset or liability related to the derivative instruments is recorded on the balance sheet as fair value of derivative assets or liabilities in accordance with ASC 815, *Derivatives and Hedging* ("ASC 815"). Changes in fair value of derivative instruments are recorded in gain or loss on derivative activity in the period of change.

Realized gains and losses on commodity-related derivatives are recorded as gain or loss on derivative activity within revenues in the consolidated statements of operations in the period incurred. Settlements of derivatives are included in cash flows from operating activities.

(o) Concentrations of Credit Risk

Financial instruments, which potentially subject us to concentrations of credit risk, consist primarily of trade accounts receivable and commodity financial instruments. Management believes the risk is limited, other than our exposure to Devon discussed below, since our customers represent a broad and diverse group of energy marketers and end users. In addition, we continually monitor and review credit exposure of our marketing counter-parties and letters of credit or other appropriate security are obtained when considered necessary to limit the risk of loss. We record reserves for uncollectible accounts on a specific identification basis since there is not a large volume of late-paying customers. We had a reserve for uncollectible receivables of $0.1 million and $0.3 million as of December 31, 2016 and 2015, respectively.

During the years ended December 31, 2016, 2015 and 2014, we had only one customer, other than the transactions with Devon, that individually represented greater than 10.0% of our midstream revenues. The customer is located in the Louisiana segment and represented 10.8%, 11.7% and 11.0% of the consolidated revenues for the years ended December 31, 2016, 2015 and 2014, respectively. The affiliate transactions with Devon represented 18.5%, 16.6% and 30.6% of the consolidated midstream revenues for the years ended December 31, 2016, 2015 and 2014, respectively. Devon and our Louisiana customer represent a significant percentage of revenues, and the loss of either as a customer would have a material adverse impact on our results of operations because the gross operating margin received from transactions with these customers are material to us.

(p) Environmental Costs

Environmental expenditures are expensed or capitalized depending on the nature of the expenditures and the future economic benefit. Expenditures that relate to an existing condition caused by past operations that do not contribute to current or future revenue generation are expensed. Liabilities for these expenditures are recorded on an undiscounted basis (or a discounted basis when the obligation can be settled at fixed and determinable amounts) when environmental assessments or clean-ups are probable and the costs can be reasonably estimated. Environmental expenditures were \$3.5 million for the year ended December 31, 2015. For the years ended December 31, 2016 and 2014, such expenditures were not material.

(q) Unit-Based Awards

Prior to the Business Combination, Devon granted certain share-based awards to members of its board of directors and selected employees. The Predecessor did not grant share-based awards because it previously participated in Devon's share-based award plans since the Predecessor comprised Devon's U.S. midstream assets. The awards granted under Devon's plans were measured at fair value on the date of grant and were recognized as expense over the applicable requisite service periods.

We recognize compensation cost related to all unit-based awards in our consolidated financial statements in accordance with ASC 718, *Compensation—Stock Compensation* ("ASC 718"). We and ENLC each have similar unit-based payment plans for employees. Unit-based compensation associated with ENLC's unit-based compensation plans awarded to directors, officers and employees of our general partner are recorded by us since ENLC has no substantial or managed operating activities other than its interests in us and EnLink Oklahoma T.O.

(r) Commitments and Contingencies

Liabilities for loss contingencies arising from claims, assessments, litigation or other sources are recorded when it is probable that a liability has been incurred and the amount can be reasonably estimated.

(s) Discontinued Operations

We classify as discontinued operations our assets that have clearly distinguishable cash flows and are in the process of being sold or have been sold. We also include as discontinued operations Predecessor assets that were not contributed in the Business Combination.

(t) Debt Issuance Costs

Costs incurred in connection with the issuance of long-term debt are deferred and recorded as interest expense over the term of the related debt. Gains or losses on debt repurchases, redemptions and debt extinguishments include any associated unamortized debt issue costs. Unamortized debt issuance costs totaling \$24.1 million and \$23.0 million as of December 31, 2016 and 2015, respectively, are included in "Long-term debt" on the consolidated balance sheets as a direct reduction from the carrying amount of long-term debt. Debt issuance costs are amortized into interest expense using the straight-line method over the term of the related debt issuance.

(u) Legal Costs Expected to be Incurred in Connection with a Loss Contingency

Legal costs incurred in connection with a loss contingency are expensed as incurred.

ENLINK MIDSTREAM PARTNERS, LP
Notes to Consolidated Financial Statements (Continued)

(v) Redeemable Non-Controlling Interest

Non-controlling interests that contain an option for the non-controlling interest holder to require us to buy out such interests for cash are considered to be redeemable non-controlling interests because the redemption feature is not deemed to be a freestanding financial instrument and because the redemption is not solely within our control. Redeemable non-controlling interest is not considered to be a component of partners' equity and is reported as temporary equity in the mezzanine section on the consolidated balance sheets. The amount recorded as redeemable non-controlling interest at each balance sheet date is the greater of the redemption value and the carrying value of the redeemable non-controlling interest (the initial carrying value increased or decreased for the non-controlling interest holder's share of net income or loss and distributions).

(w) Adopted Accounting Standards

In January 2016, we adopted ASU 2015-03, Interest— *Imputation of Interest (Topic 835): Simplifying the Presentation of Debt Issuance Costs.* The update requires debt issuance costs related to a recognized debt liability to be presented on the balance sheet as a direct deduction from the carrying amount of that debt liability and requires retrospective application. The retrospective application of this new accounting guidance resulted in the reclassification of $23.0 million of debt issuance costs from "Other assets, net" to "Long-term debt" in our consolidated balance sheet as of December 31, 2015.

In January 2016, we adopted ASU 2015-17,*Balance Sheet Classification of Deferred Taxes* on a prospective basis. This new standard required that deferred tax assets and liabilities be classified as noncurrent in our consolidated balance sheet.

In January 2016, we adopted ASU 2015-16,*Business Combinations (Topic 805): Simplifying the Accounting for Measurement-Period Adjustments*, which eliminates the requirement for an acquirer to retrospectively adjust the financial statements for measurement-period adjustments that occur in periods after a business combination is consummated. The adoption had no impact on our consolidated financial statements or related disclosures.

In January 2016, we adopted ASU 2015-02,*Consolidation (Topic 810): Amendments to the Consolidation Analysis*. The update provides additional guidance to reporting entities in evaluating whether certain legal entities, such as limited partnerships, limited liability corporations and securitization structures, should be consolidated. The update is considered to be an improvement on current accounting requirements as it reduces the number of existing consolidation models. The adoption had no impact on our consolidated financial statements or related disclosures.

In January 2016, we adopted ASU 2015-06,*Effects on Historical Earnings per Unit of Master Limited Partnership Dropdown Transactions (a Consensus of the FASB Emerging Issues Task Force)* ("ASU 2015-06"), which requires a master limited partnership (MLP) to allocate earnings (losses) of a transferred business entirely to the general partner when computing earnings per unit (EPU) for periods before the dropdown transaction occurred. The EPU that the limited partners previously reported would not change as a result of the dropdown transaction. ASU 2015-06 also requires an MLP to disclose the effects of the dropdown transaction on EPU for the periods before and after the dropdown transaction occurred. ASU 2015-06 is effective for the fiscal years beginning after December 15, 2015, and interim periods within those annual periods. ASU 2015-06 requires retrospective application and early adoption is permitted. The update was effective for us beginning on January 1, 2016 and had no impact on our consolidated financial statements or related disclosures.

In August 2016, the Financial Accounting Standards Board ("FASB") issued ASU 2016-15,*Statement of Cash Flows (Topic 230) — Classification of Certain Cash Receipts and Cash Payments* ("ASU 2016-15"). ASU 2016-15 addresses the classification and presentation of certain cash receipts and cash payments related to debt prepayment or debt extinguishment costs, contingent consideration payments made after a business combination, proceeds from the settlement of insurance claims, distributions received from equity method investees, and other specific cash flow issues. ASU 2016-15 is effective for annual reporting periods beginning after December 15, 2017, including interim periods within those annual periods, and should be applied using a retrospective transition method to each period presented. Early application is permitted, including adoption in an interim period. In September 2016, we elected to early adopt

ASU 2016-15 effective January 1, 2016. The adoption had no impact on our consolidated financial statements or related disclosures.

(x) Accounting Standards to be Adopted in Future Periods

In March 2016, the FASB issued ASU 2016-09, *Improvements to Employee Share-Based Payment Accounting, which amends ASC Topic 718, Compensation — Stock Compensation* ("ASU 2016-09"). First, ASU 2016-09 will require all of the tax effects related to share-based payments at settlement (or expiration) to be recorded through the income statement and is required to be applied prospectively. Second ASU 2016-09 allows entities to withhold taxes of an amount up to the employees' maximum individual tax rate in the relevant jurisdiction without resulting in liability classification of the award, and is required to be adopted using a modified retrospective approach. Third, under ASU 2016-09, forfeitures can be estimated, as currently required, or recognized when they occur. If elected, the change to recognize forfeitures when they occur must be adopted using a modified retrospective approach. ASU 2016-09 is effective for annual reporting periods beginning after December 15, 2016 including interim periods within those annual periods. Early adoption is permitted. We do not expect this standard to materially impact our consolidated financial statements or related disclosures.

In February 2016, the FASB issued ASU 2016-02, *Leases (Topic 842) - Amendments to the FASB Accounting Standards Codification* ("ASU 2016-02"). Lessees will need to recognize virtually all of their leases on the balance sheet, by recording a right-of-use asset and lease liability. Lessor accounting is similar to the current model, but updated to align with certain changes to the lessee model and the new revenue recognition standard. Existing sale-leaseback guidance is replaced with a new model applicable to both lessees and lessors. Additional revisions have been made to embedded leases, reassessment requirements, and lease term assessments including variable lease payment, discount rate and lease incentives. ASU 2016-02 is effective for annual reporting periods beginning after December 15, 2018 including interim periods within those annual periods. Early adoption is permitted, and is required to be adopted using a modified retrospective transition. We are currently evaluating the impact this standard will have on our consolidated financial statements and related disclosures.

In May 2014, the FASB issued ASU 2014-09, *Revenue from Contracts with Customers* ("ASU 2014-09"), which established Accounting Standards Codification Topic 606, *Revenue from Contracts with Customers* ("ASC 606). ASC 606 will replace existing revenue recognition requirements in GAAP and will require entities to recognize revenue at an amount that reflects the consideration to which we expect to be entitled in exchange for transferring goods or services to a customer. ASC 606 will also require significantly expanded disclosures regarding the qualitative and quantitative information of our nature, amount, timing, and uncertainty of revenue and cash flows arising from contracts with customers. In May 2016, the FASB issued ASU 2016-12*, Revenue from Contracts with Customers (Topic 606): Narrow-Scope Improvements and Practical Expedients* ("ASU 2016-12"), which updated ASU 2014-09. ASU 2016-12 clarifies certain core recognition principles including collectability, sales tax presentation, noncash consideration, contract modifications and completed contracts at transition and disclosures no longer required if the full retrospective transition method is adopted. ASU 2014-09 and ASU 2016-12 are effective for annual reporting periods beginning after December 15, 2017, including interim periods within those annual periods, and are to be applied using either the modified retrospective or full retrospective transition methods, with early application permitted for annual reporting periods beginning after December 15, 2016. We plan to use the modified retrospective transition method and do not plan to early adopt ASC 606. We have aggregated and reviewed our contracts that are within the scope of ASC 606. Based on our evaluation to-date, we do not anticipate this standard will have a material impact on our consolidated financial statements. We continue to evaluate the impacts ASC 606 will have on our disclosures.

(3) Acquisitions

Chevron Acquisition

On November 1, 2014, we acquired, from affiliates of Chevron Corporation, Gulf Coast natural gas pipeline assets predominantly located in southern Louisiana, together with 100% of the voting interests in certain entities, for approximately $231.5 million in cash. The natural gas assets include natural gas pipelines spanning from Beaumont, Texas to the Mississippi River corridor and working natural gas storage capacity in southern Louisiana. The transaction was accounted for using the acquisition method, which requires, among other things, that assets acquired and liabilities assumed be recognized at their fair values as of the acquisition date.

The following table presents the fair value of the identified assets received and liabilities assumed at the acquisition date (in millions):

Purchase Price Allocation:	
Assets acquired:	
Property, plant and equipment	$ 225.3
Intangibles	13.0
Liabilities assumed:	
Current liabilities	(6.8)
Total identifiable net assets	$ 231.5

We recognized intangible assets related to customer relationships. The acquired intangible assets related to customer relationships will be amortized on a straight-line basis over the estimated customer contract life of approximately 20 years.

We incurred $0.6 million of direct transaction costs for the year ended December 31, 2015. These costs are included in general and administrative costs in the accompanying consolidated statements of operations.

LPC Acquisition

On January 31, 2015, we acquired 100% of the voting equity interests of LPC Crude Oil Marketing LLC ("LPC"), which has crude oil gathering, transportation and marketing operations in the Permian Basin, for approximately $108.1 million. The transaction was accounted for using the acquisition method.

The following table presents the fair value of the identified assets received and liabilities assumed at the acquisition date (in millions):

Purchase Price Allocation:	
Assets acquired:	
Current assets (including $21.1 million in cash)	$ 107.4
Property, plant and equipment	29.8
Intangibles	43.2
Goodwill	29.6
Liabilities assumed:	
Current liabilities	(97.9)
Deferred tax liability	(4.0)
Total identifiable net assets	$ 108.1

We recognized intangible assets related to customer relationships and trade name. The acquired intangible assets related to customer relationships are amortized on a straight-line basis over the estimated customer life of approximately 10 years.

Goodwill recognized from the acquisition primarily relates to the value created from additional growth opportunities and greater operating leverage in the Permian Basin. All such goodwill is allocated to our Crude and Condensate segment.

We incurred $0.3 million of direct transaction costs for the year ended December 31, 2015. These costs are included in general and administrative costs in the accompanying consolidated statements of operations.

ENLINK MIDSTREAM PARTNERS, LP
Notes to Consolidated Financial Statements (Continued)

For the period from January 31, 2015 to December 31, 2015, we recognized $1.1 billion of revenues and $0.9 million of net income related to the assets acquired.

Coronado Acquisition

On March 16, 2015, we acquired 100% of the voting equity interests in Coronado Midstream Holdings LLC ("Coronado"), which owns natural gas gathering and processing facilities in the Permian Basin, for approximately $600.3 million. The purchase price consisted of $240.3 million in cash, 6,704,285 of our common units and 6,704,285 of our Class C Common Units.

The following table presents the fair value of the identified assets received and liabilities assumed at the acquisition date (in millions):

Purchase Price Allocation:	
Assets acquired:	
Current assets (including $1.4 million in cash)	$ 20.8
Property, plant and equipment	302.1
Intangibles	281.0
Goodwill	18.7
Liabilities assumed:	
Current liabilities	(22.3)
Total identifiable net assets	$ 600.3

We recognized intangible assets related to customer relationships. The acquired intangible assets are amortized on a straight-line basis over the estimated customer life of approximately 10 years. Goodwill recognized from the acquisition primarily relates to the value created from additional growth opportunities and greater operating leverage in the Permian Basin. All such goodwill is allocated to our Texas segment.

We incurred $3.1 million of direct transaction costs for the year ended December 31, 2015. These costs are included in general and administrative costs in the accompanying consolidated statements of operations.

For the period from March 16, 2015 to December 31, 2015, we recognized $182.0 million of revenues and $14.2 million of net loss related to the assets acquired.

Matador Acquisition

On October 1, 2015, we acquired 100% of the voting equity interests in a subsidiary of Matador Resources Company ("Matador"), which has gathering and processing assets operations in the Delaware Basin, for approximately $141.3 million. The transaction was accounted for using the acquisition method.

The following table presents the fair value of the identified assets received and liabilities assumed at the acquisition date (in millions):

Purchase Price Allocation:	
Assets acquired:	
Current assets	$ 1.1
Property, plant and equipment	35.5
Intangibles	98.8
Goodwill	10.7
Liabilities assumed:	
Current liabilities	(4.8)
Total identifiable net assets	$ 141.3

ENLINK MIDSTREAM PARTNERS, LP
Notes to Consolidated Financial Statements (Continued)

We recognized intangible assets related to customer relationships. The acquired intangible assets are amortized on a straight-line basis over the estimated customer 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 Permian Basin. All such goodwill is allocated to our Texas segment.

We incurred $0.1 million of direct transaction costs for the year ended December 31, 2015. These costs are included in general and administrative costs in the accompanying consolidated statements of operations.

For the period from October 1, 2015 to December 31, 2015, we recognized $5.6 million of revenues and $0.7 million of net loss related to the assets acquired.

Deadwood Acquisition

Prior to November 2015, we co-owned the Deadwood natural gas processing plant with a subsidiary of Apache Corporation ("Apache"). On November 16, 2015, we acquired Apache's 50% ownership interest in the Deadwood natural gas processing facility for approximately $40.1 million, all of which is considered property, plant and equipment. The transaction was accounted for using the acquisition method. Direct transaction costs attributable to this acquisition were less than $0.1 million.

For the period from November 16, 2015 to December 31, 2015, we recognized $3.5 million of revenues and $1.3 million of net income related to the assets acquired.

EMH Drop Downs

On February 17, 2015, we acquired an additional 25% limited partner interest in Midstream Holdings from Acacia in the February 2015 EMH Drop Down. As consideration for the February 2015 Transferred Interests, we issued 31.6 million of our Class D Common Units to Acacia with an implied value of $925.0 million. The Class D Common Units were substantially similar in all respects to our common units, except that they received only a pro rata distribution for the fiscal quarter ended March 31, 2015. The Class D Common Units converted into common units on a one-for-one basis on May 4, 2015.

On May 27, 2015, we acquired the remaining 25% limited partner interest in Midstream Holdings from Acacia in the May 2015 EMH Drop Down in exchange for 36.6 million of our Class E Common Units with an implied value of $900.0 million. The Class E Common Units are substantially similar in all respects to our common units, except that they received only a pro rata distribution for the fiscal quarter ended June 30, 2015. The Class E Common Units converted into common units on a one-for-one basis on August 3, 2015. After giving effect to the EMH Drop Downs, we own 100% of Midstream Holdings. The period of common control for EMH began on March 7, 2014, the effective date of the Business Combination.

We accounted for the acquisition of the EMH Drop Downs from Acacia as a transfer between entities under common control in accordance with ASC 805, *Business Combinations* ("ASC 805"). As such, the February 2015 Transferred Interests and May 2015 Transferred Interests were recorded on our books at historical cost on the date of transfer, which was February 17, 2015 and May 27, 2015, respectively. The "Transfer of interest in Midstream Holdings" presented in the consolidated statements of changes in partners' equity represents the adjustment to equity due to the recast to offset distributions paid to ENLC for its related ownership during the period January 1, 2015 to May 27, 2015.

VEX Pipeline Drop Down

On April 1, 2015, we acquired the Victoria Express Pipeline and related truck terminal and storage assets located in the Eagle Ford Shale in south Texas, together with 100% of the voting equity interests (the "VEX interests") in certain entities, from Devon in a drop down transaction (the "VEX Drop Down"). The aggregate consideration paid by us consisted of $166.7 million in cash, 338,159 common units representing our limited partner interests with an aggregate value of approximately $9.0 million and our assumption of up to $40.0 million in certain construction costs related to VEX. The VEX pipeline is a multi-grade crude oil pipeline located in the Eagle Ford Shale. Other VEX assets at the destination of the pipeline include a truck unloading terminal, above-ground storage and rights to barge loading docks. The acquisition has been accounted for as an acquisition under common control under ASC 805, resulting in the retrospective adjustment of our prior results. As such, the VEX Interests were recorded on our books at historical cost on the date of transfer of $131.0 million. The difference between the historical cost of the net assets and consideration given was $35.7 million and is recognized as a distribution to Devon. Construction costs paid by Devon during the first quarter of 2015 totaling $25.6 million are reflected as contributions from Devon in our consolidated statements of changes in partners' equity and consolidated statements of cash flows for the year ended December 31, 2015. The period of common control for VEX began on February 28, 2014, the effective date of the acquisition of the VEX Interests by Devon.

E2 Drop Down

On October 22, 2014, we acquired all remaining voting equity interests (the "E2 interests") in EnLink Appalachian Compression, LLC (formerly, E2 Appalachian Compression, LLC) and E2 Energy Services, LLC (together "E2") in a drop down transaction from EMI (the "E2 Drop Down"). The total consideration for the transaction was approximately $194.0 million, including a cash payment of $163.0 million and the issuance of approximately 1.0 million common units (valued at approximately $31.2 million based on the October 22, 2014 closing price of the common units). This acquisition has been accounted for as an acquisition under common control under ASC 805. The period of common control for E2 began on March 7, 2014, the effective date of the Business Combination.

Pro Forma of Acquisitions for the Years Ended 2015 and 2014

The following unaudited pro forma condensed financial information (in millions, except for per unit data) for the year ended December 31, 2015 and 2014 gives effect to the Business Combination, November 2014 Chevron acquisition, January 2015 LPC acquisition, March 2015 Coronado acquisition, October 2015 Matador acquisition, EMH Drop Downs, VEX Drop Down and E2 Drop Down as if they had occurred on January 1, 2014. The unaudited pro forma condensed financial information has been included for comparative purposes only and is not necessarily indicative of the results that might have occurred had the transactions taken place on the dates indicated and is not intended to be a projection of future results.

	Year Ended December 31,	
	2015	2014
Pro forma total revenues (1)	$ 4,585.5	$ 5,679.2
Pro forma net income (loss)	$ (1,381.8)	$ 266.9
Pro forma net income (loss) attributable to EnLink Midstream Partners, LP	$ (1,381.4)	$ 267.2
Pro forma net income (loss) per common unit:		
Basic	$ (4.63)	$ 0.42
Diluted	$ (4.63)	$ 0.42

(1) On January 1, 2014, Midstream Holdings entered into gathering and processing agreements with Devon, which are described in "Note 5— Related Party Transactions."

EnLink Oklahoma T.O. Acquisition

On January 7, 2016, we and ENLC acquired an 84% and 16% voting interest, respectively, in EnLink Oklahoma T.O. for approximately $1.4 billion. The first installment of $1.02 billion for the acquisition was paid at closing. The second installment of $250.0 million was paid on January 6, 2017, and the final installment of $250.0 million is due no later than January 7, 2018. The installment payables are valued net of discount within the total purchase price.

The first installment of approximately $1.02 billion was funded by (a) approximately $783.6 million in cash paid by us, the majority of which was derived from the proceeds from the issuance of Preferred Units, and (b) 15,564,009 common units representing limited liability company interests in ENLC issued directly by ENLC and approximately $22.2 million in cash paid by ENLC. The transaction was accounted for using the acquisition method.

ENLINK MIDSTREAM PARTNERS, LP
Notes to Consolidated Financial Statements (Continued)

The following table presents the considerations we paid and the fair value of the identified assets received and liabilities assumed at the acquisition date (in millions):

Consideration:		
Cash	$	783.6
Total installment payable, net of discount of $79.1 million assuming payments are made on January 7, 2017 and 2018		420.9
Contribution from ENLC		237.1
Total consideration	$	1,441.6
Purchase Price Allocation:		
Assets acquired:		
Current assets (including $12.8 million in cash)	$	23.0
Property, plant and equipment		406.1
Intangibles		1,051.3
Liabilities assumed:		
Current liabilities		(38.8)
Total identifiable net assets	$	1,441.6

The fair value of assets acquired and liabilities assumed are based on inputs that are not observable in the market and thus represent Level 3 inputs. We recognized intangible assets related to customer relationships and determined their fair value using the income approach. The acquired intangible assets are amortized on a straight-line basis over the estimated customer life of approximately 15 years.

We incurred $4.4 million and $0.4 million of direct transaction costs for the year ended December 31, 2016 and December 31, 2015, respectively. These costs are incurred in general and administrative costs in the accompanying consolidated statements of operations.

For the period from January 7, 2016 to December 31, 2016, we recognized $246.1 million of revenues and $34.1 million of net loss, of which $5.5 million is attributable to non-controlling interests, related to the assets acquired.

Pro Forma of the EnLink Oklahoma T.O. Acquisition

The following unaudited pro forma condensed financial information (in millions, except for per unit data) for the year ended December 31, 2016 and 2015 gives effect to the January 2016 acquisition of EnLink Oklahoma T.O as if it had occurred on January 1, 2015. The unaudited pro forma condensed financial information has been included for comparative purposes only and is not necessarily indicative of the results that might have occurred had the transaction taken place on the dates indicated and is not intended to be a projection of future results.

	2016		2015	
Pro forma total revenues	$	4,254.4	$	4,514.3
Pro forma net loss	$	(574.1)	$	(1,454.5)
Pro forma net loss attributable to EnLink Midstream Partners, LP	$	(565.8)	$	(1,441.8)
Pro forma net loss per common unit:				
Basic	$	(2.03)	$	(5.10)
Diluted	$	(2.03)	$	(5.10)

ENLINK MIDSTREAM PARTNERS, LP
Notes to Consolidated Financial Statements (Continued)

(4) Goodwill and Intangible Assets

Goodwill

Goodwill is the cost of an acquisition less the fair value of the net identifiable assets of the acquired business. The fair value of goodwill is based on inputs that are not observable in the market and thus represent Level 3 inputs. We evaluate goodwill for impairment annually as of October 31, and whenever events or changes in circumstances indicate it is more likely than not that the fair value of a reporting unit is less than its carrying amount. We first assess qualitative factors to evaluate whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount as the basis for determining whether it is necessary to perform the two-step goodwill impairment test. We may elect to perform the two-step goodwill impairment test without completing a qualitative assessment. If a two-step goodwill impairment test is elected or required, the first step involves comparing the fair value of the reporting unit to its carrying amount. If the carrying amount of a reporting unit exceeds its fair value, the second step of the process involves comparing the implied fair value of goodwill to the carrying value of the goodwill for that reporting unit. If the carrying value of the goodwill of a reporting unit exceeds the implied fair value of that goodwill, the excess of the carrying value over the implied fair value is recognized as an impairment loss.

We perform our goodwill assessments at the reporting unit level for all reporting units. We use a discounted cash flow analysis to perform the assessments. Key assumptions in the analysis include the use of an appropriate discount rate, terminal year multiples and estimated future cash flows including volume and price forecasts and estimated operating and general and administrative costs. In estimating cash flows, we incorporate current and historical market and financial information, among other factors. Our impairment determinations involved significant assumptions and judgments, as discussed above. Differing assumptions regarding any of these inputs could have a significant effect on the various valuations. If actual results are not consistent with our assumptions and estimates, or our assumptions and estimates change due to new information, we may be exposed to additional goodwill impairment charges, which would be recognized in the period in which the carrying value exceeds fair value.

Impairment Analysis for the Year Ended December 31, 2015

During the third quarter of 2015, we determined that sustained weakness in the overall energy sector, driven by low commodity prices together with a decline in our unit price, caused a change in circumstances warranting an interim impairment test. We also performed our annual impairment analysis during the fourth quarter of 2015. Although our established annual effective date for this goodwill analysis is October 31, we updated the effective date for this impairment analysis for the 2015 annual period to December 31, 2015 due to continued declines in commodity prices and our unit price during the fourth quarter of 2015.

Using the fair value approaches described above, in step one of the goodwill impairment test, we determined that the estimated fair values of our Louisiana, Texas and Crude and Condensate reporting unit were less than their carrying amounts, primarily related to commodity prices, volume forecasts and discount rates. The second step of the goodwill impairment test measures the amount of impairment loss and allocated the estimated fair value of the reporting unit among all of the assets and liabilities of the reporting unit as if the reporting unit had been acquired in a business combination. Based on this analysis, a goodwill impairment loss for our Louisiana, Texas, and Crude and Condensate reporting units in the amount of $1,328.2 million was recognized for the year ended December 31, 2015 and is included as an impairment loss in the consolidated statements of operations.

We concluded that the fair value of goodwill for our Oklahoma reporting unit exceeded its carrying value, and the amount of goodwill disclosed on the consolidated balance sheet associated with this remaining reporting unit was recoverable. Therefore, no other goodwill impairment was identified or recorded for this reporting unit as a result of our annual goodwill assessment.

Impairment Analysis for the Year Ended December 31, 2016

During February 2016, we determined that continued further weakness in the overall energy sector, driven by low commodity prices together with a further decline in our unit price subsequent to year-end, caused a change in circumstances warranting an interim impairment test. Based on these triggering events, we performed a goodwill impairment analysis in the first quarter of 2016 on all reporting units. Based on this analysis, a goodwill impairment loss for our Texas and Crude and Condensate reporting units in the amount of $566.3 million was recognized in the first quarter of 2016 and is included as an impairment loss in the consolidated statement of operations for the year ended December 31, 2016.

We concluded that the fair value of our Oklahoma reporting unit exceeded its carrying value, and the amount of goodwill disclosed on the consolidated balance sheet associated with this reporting unit is recoverable. Therefore, no other goodwill impairment was identified or recorded for this reporting unit as a result of our goodwill impairment analysis.

During our annual impairment test for 2016 performed as of October 31, 2016, we determined that no further impairments were required for the year ended December 31, 2016. The estimated fair value of our reporting units may be impacted in the future by a further decline in our unit price or a continuing prolonged period of lower commodity prices which may adversely affect our estimate of future cash flows, both of which could result in future goodwill impairment charges for our reporting units.

The table below provides a summary of our change in carrying amount of goodwill (in millions), by assigned reporting unit:

	Texas	Louisiana	Oklahoma	Crude and Condensate	Corporate	Totals
Year Ended December 31, 2016						
Balance, beginning of period	$ 703.5	$ —	$ 190.3	$ 93.2	$ —	$ 987.0
Impairment	(473.1)	—	—	(93.2)	—	(566.3)
Acquisition adjustment	1.6	—	—	—	—	1.6
Balance, end of period	$ 232.0	$ —	$ 190.3	$ —	$ —	$ 422.3
Year Ended December 31, 2015						
Balance, beginning of period	$ 1,168.2	$ 786.8	$ 190.3	$ 112.5	$ —	$ 2,257.8
Acquisitions (1)	27.8	—	—	29.6	—	57.4
Impairment	(492.5)	(786.8)	—	(48.9)	—	(1,328.2)
Balance, end of period	$ 703.5	$ —	$ 190.3	$ 93.2	$ —	$ 987.0

(1) See “Note 3—Acquisitions” for further discussion.

Intangible Assets

Intangible assets associated with customer relationships are amortized on a straight-line basis over the expected period of benefits of the customer relationships, which range from 10 to 20 years.

During 2016 and 2015, we reviewed our various assets groups for impairment due to the triggering events described in the goodwill impairment analysis above. During 2015, the undiscounted cash flows related to one of our assets groups in the Crude and Condensate segment were not in excess of its related carrying value. We estimated the fair value of this reporting unit and determined the fair of the intangible assets was not in excess of their carrying value. This resulted in a $223.1 million impairment of intangible assets in our Crude and Condensate segment, and this non-cash impairment charge is included as an impairment loss on the consolidated statements of operations for the year ended December 31, 2015. During 2016, the undiscounted cash flows of our assets exceeded their carrying values, and no impairment was recorded. We utilized Level 3 fair value measurements in our impairment analysis of this definite-lived intangible asset, which included discounted cash flow assumptions by management consistent with those utilized in our goodwill impairment analysis.

ENLINK MIDSTREAM PARTNERS, LP
Notes to Consolidated Financial Statements (Continued)

The following table represents our change in carrying value of intangible assets for the periods stated (in millions):

	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount
Year Ended December 31, 2016			
Customer relationships, beginning of period	$ 744.5	$ (54.6)	$ 689.9
Acquisitions	1,051.3	—	1,051.3
Amortization expense	—	(117.0)	(117.0)
Customer relationships, end of period	$ 1,795.8	$ (171.6)	$ 1,624.2
Year Ended December 31, 2015			
Customer relationships, beginning of period	$ 569.5	$ (36.5)	$ 533.0
Acquisitions	436.0	—	436.0
Amortization expense	—	(56.0)	(56.0)
Impairment	(261.0)	37.9	(223.1)
Customer relationships, end of period	$ 744.5	$ (54.6)	$ 689.9

The weighted average amortization period for intangible assets is 13.7 years. Amortization expense for intangibles was approximately $117.0 million, $56.0 million, and $36.5 million for the years ended December 31, 2016, 2015 and 2014, respectively.

The following table summarizes our estimated aggregate amortization expense for the next five years (in millions):

2017	$ 117.9
2018	117.9
2019	117.9
2020	117.9
2021	117.9
Thereafter	1,034.7
Total	$ 1,624.2

(5) Related Party Transactions

We engage in various transactions with Devon and other related parties. For the years ended December 31, 2016, 2015 and 2014, Devon was a significant customer to us. Devon accounted for 18.5%, 16.6% and 30.6% of our revenues for the years ended December 31, 2016, 2015 and 2014, respectively. We had an accounts receivable balance related to transactions with Devon of $100.2 million and $110.8 million as of December 31, 2016 and 2015, respectively. Additionally, we had an accounts payable balance related to transactions with Devon of $10.4 million and $14.8 million as of December 31, 2016 and 2015, respectively. Management believes these transactions are executed on terms that are fair and reasonable and are consistent with terms for transactions with unrelated third parties. The amounts related to related party transactions are specified in the accompanying financial statements.

Gathering, Processing and Transportation Agreements Associated with Our Business Combination with Devon

As described in “Note 1—Organization and Summary of Significant Agreements,” Midstream Holdings was previously a wholly-owned subsidiary of Devon, and all of its assets were contributed to it by Devon. On January 1, 2014, in connection with the consummation of the Business Combination, EnLink Midstream Services, LLC, a wholly-owned subsidiary of Midstream Holdings (“EnLink Midstream Services”), entered into 10-year gathering and processing agreements with Devon pursuant to which EnLink Midstream Services provides gathering, treating, compression, dehydration, stabilization, processing and fractionation services, as applicable, for natural gas delivered by Devon Gas Services, L.P., a subsidiary of Devon (“Gas Services”), to Midstream Holdings’ gathering and processing systems in the Barnett, Cana-Woodford and Arkoma-Woodford Shales. On January 1, 2014, SWG Pipeline, L.L.C. (“SWG Pipeline”), another wholly-owned subsidiary of Midstream Holdings, entered into a 10-year gathering agreement with Devon pursuant to which SWG Pipeline provides gathering, treating, compression, dehydration and redelivery services, as applicable, for natural gas delivered by Gas Services to another of our gathering systems in the Barnett Shale.

These agreements provide Midstream Holdings with dedication of all of the natural gas owned or controlled by Devon and produced from or attributable to existing and future wells located on certain oil, natural gas and mineral leases covering land within the acreage dedications, excluding properties previously dedicated to other natural gas gathering systems not owned and operated by Devon. Pursuant to the gathering and processing agreements entered into on January 1, 2014, Devon has committed to deliver specified average minimum daily volumes, referred to as MVCs, of natural gas to Midstream Holdings' gathering systems in the Barnett, Cana-Woodford and Arkoma-Woodford Shales during each calendar quarter for a five-year period that expires on January 1, 2019. We recognized revenue from MVCs attributable to Devon of $46.2 million and $24.4 million for the years ended December 31, 2016 and 2015, respectively. Devon is entitled to firm service, meaning that if capacity on a system is curtailed or reduced, or capacity is otherwise insufficient, Midstream Holdings will take delivery of as much Devon natural gas as is permitted in accordance with applicable law.

The gathering and processing agreements are fee-based, and Midstream Holdings is paid a specified fee per MMBtu for natural gas gathered on Midstream Holdings' gathering systems and a specified fee per MMBtu for natural gas processed. The particular fees, all of which are subject to an automatic annual inflation escalator at the beginning of each year, differ from one system to another and do not contain a fee redetermination clause.

In connection with the closing of the Business Combination, Midstream Holdings entered into an agreement with a wholly-owned subsidiary of Devon pursuant to which Midstream Holdings provides transportation services to Devon on its Acacia pipeline.

EnLink Oklahoma T.O. Gathering and Processing Agreement with Devon

In January 2016, in connection with the acquisition of EnLink Oklahoma T.O., we acquired a Gas Gathering and Processing Agreement with Devon Energy Production Company, L.P. ("DEPC") pursuant to which EnLink Oklahoma T.O. provides gathering, treating, compression, dehydration, stabilization, processing and fractionation services, as applicable, for natural gas delivered by DEPC. The agreement has an MVC that will remain in place during each calendar quarter for five years and an overall term of approximately 15 years. Additionally, the agreement provides EnLink Oklahoma T.O. with dedication of all of the natural gas owned or controlled by DEPC and produced from or attributable to existing and future wells located on certain oil, natural gas and mineral leases covering land within the acreage dedications, excluding properties previously dedicated to other natural gas gathering systems not owned and operated by DEPC. DEPC is entitled to firm service, meaning a level of gathering and processing service in which DEPC's reserved capacity may not be interrupted, except due to force majeure, and may not be displaced by another customer or class of service.

Cedar Cove Joint Venture

On November 9, 2016, we formed a joint venture (the "Cedar Cove JV") with Kinder Morgan, Inc. consisting of gathering and compression assets in Blaine County, Oklahoma. Under a fifteen year, fixed-fee agreement, all gas gathered by the Cedar Cove JV will be processed at our central Oklahoma processing system. For the period from November 9, 2016 through December 31, 2016, revenue generated from processing gas from the Cedar Cove JV was classified as "Midstream services – related parties" on the consolidated statements of operations and was immaterial to our overall financial results.

Other Commercial Relationships with Devon

As noted above, we continue to maintain a customer relationship with Devon originally established prior to the Business Combination pursuant to which we provide gathering, transportation, processing and gas lift services to Devon in exchange for fee-based compensation under several agreements with Devon. The terms of these agreements vary, but the agreements began to expire in January 2016 and continue to expire through July 2021, renewing automatically for month-to-month or year-to-year periods unless canceled by Devon prior to expiration. In addition, we have agreements with Devon pursuant to which we purchase and sell NGLs, gas and crude oil and pays or receives, as applicable, a margin-based fee. These NGL, gas and crude oil purchase and sale agreements have month-to-month terms.

VEX Transportation Agreement

In connection with the VEX acquisition, we became party to a five-year transportation services agreement with Devon pursuant to which the we provide transportation services to Devon on the VEX pipeline. This agreement includes a five-year MVC with Devon. The MVC was executed in June 2014, and the initial term expires July 2019.

Transition Services Agreement with Devon

In connection with the consummation of the Business Combination, we entered into a transition services agreement with Devon pursuant to which Devon provides certain services to us with respect to the business and operations of Midstream Holdings, and we provide certain services to Devon. General and administrative expenses related to the transition service agreement were $0.3 million, $0.2 million and $3.0 million for years ended December 31, 2016, 2015 and 2014, respectively. We received $0.3 million from Devon under the transition services agreement for each of the years ended December 31, 2016, 2015 and 2014.

Drop Down Transactions

During the fourth quarter of 2014 and the first half of 2015, we acquired assets from ENLC and Devon through drop down transactions. See “Note 3—Acquisitions” for further discussion.

Predecessor Affiliate Transactions

Prior to March 7, 2014, affiliate transactions relate to Predecessor transactions consisting of sales to and from affiliates, services provided by affiliates, cost allocations from affiliates and centralized cash management activities performed by affiliates.

ENLINK MIDSTREAM PARTNERS, LP
Notes to Consolidated Financial Statements (Continued)

The following presents financial information for the Predecessor's affiliate transactions and other transactions with Devon, all of which are settled through an adjustment to equity prior to March 7, 2014 (in millions):

	Year Ended December 31, 2014
Continuing Operations:	
Operating revenues - related parties	$ (436.4)
Operating expenses - related parties	340.0
Net related party transactions	(96.4)
Capital expenditures	16.2
Other third-party transactions, net	58.9
Net third-party transactions	75.1
Net cash distributions to Devon - continuing operations	(21.3)
Non-cash distribution of net assets to Devon	(6.3)
Total net distributions per equity	$ (27.6)
Discontinued operations:	
Operating revenues - related parties	$ (10.4)
Operating expenses - related parties	5.0
Net related party transactions	(5.4)
Capital expenditures	0.6
Other third-party transactions, net	0.4
Net third-party transactions	1.0
Net distributions to Devon and non-controlling interests - discontinued operations	(4.4)
Non-cash distribution of net assets to Devon	(39.9)
Total net distributions per equity	$ (44.3)
Total distributions- continuing and discontinued operations	$ (71.9)

Share-based compensation costs included in the management services fee charged to Midstream Holdings by Devon were approximately $2.8 million for the year ended December 31, 2014. Pension, postretirement and employee savings plan costs included in the management services fee charged to us by Devon were approximately $1.6 million for the year ended December 31, 2014. These amounts are included in general and administrative expenses in the accompanying statements of operations.

Transactions with ENLC

ENLC paid us $2.3 million, $2.1 million, and $1.2 million as reimbursement during the years ended December 31, 2016, 2015, and 2014, respectively, to cover its portion of administrative and compensation costs for officers and employees that perform services for ENLC. This reimbursement is evaluated on an annual basis. Officers and employees that perform services for ENLC provide an estimate of the portion of their time devoted to such services. A portion of their annual compensation (including bonuses, payroll taxes and other benefit costs) is allocated to ENLC for reimbursement based on these estimates. In addition, an administrative burden is added to such costs to reimburse us for additional support costs, including, but not limited to, consideration for rent, office support and information service support.

On October 29, 2015, we issued 2,849,100 common units at an offering price of $17.55 per common unit to a subsidiary of ENLC for aggregate consideration of approximately $50.0 million in a private placement transaction.

(6) Long-Term Debt

As of December 31, 2016 and 2015, long-term debt consisted of the following (in millions):

	December 31, 2016			December 31, 2015		
	Outstanding Principal	Premium (Discount)	Long-Term Debt	Outstanding Principal	Premium (Discount)	Long-Term Debt
Partnership credit facility, due 2020 (1)	$ 120.0	$ —	$ 120.0	$ 414.0	$ —	$ 414.0
2.70% Senior unsecured notes due 2019	400.0	(0.3)	399.7	400.0	(0.4)	399.6
7.125% Senior unsecured notes due 2022	162.5	16.0	178.5	162.5	18.9	181.4
4.40% Senior unsecured notes due 2024	550.0	2.5	552.5	550.0	2.9	552.9
4.15% Senior unsecured notes due 2025	750.0	(1.1)	748.9	750.0	(1.2)	748.8
4.85% Senior unsecured notes due 2026	500.0	(0.7)	499.3	—	—	—
5.60% Senior unsecured notes due 2044	350.0	(0.2)	349.8	350.0	(0.2)	349.8
5.05% Senior unsecured notes due 2045	450.0	(6.6)	443.4	450.0	(6.9)	443.1
Other debt	—	—	—	0.2	—	0.2
Debt classified as long-term	$ 3,282.5	$ 9.6	$ 3,292.1	$ 3,076.7	$ 13.1	$ 3,089.8
Debt issuance cost (2)			(24.1)			(23.0)
Long-term debt, net of unamortized issuance cost			$ 3,268.0			$ 3,066.8

(1) Bears interest based on Prime and/or LIBOR plus an applicable margin. The effective interest rate was 2.3% and 1.8% at December 31, 2016 and 2015, respectively.
(2) Net of amortization of $8.3 million and $4.7 million at December 31, 2016 and 2015, respectively.

Maturities

Maturities for the long-term debt as of December 31, 2016 are as follows (in millions):

2017	$ —
2018	—
2019	400.0
2020	120.0
2021	—
Thereafter	2,762.5
Subtotal	3,282.5
Add: net premium	9.6
Less: debt issuance cost	(24.1)
Long-term debt, net of unamortized issuance cost	$ 3,268.0

Credit Facility

We have a $1.5 billion unsecured revolving credit facility, which includes a $500.0 million letter of credit subfacility that matures on March 6, 2020. Under our credit facility, we are permitted to (1) subject to certain conditions and the receipt of additional commitments by one or more lenders, increase the aggregate commitments under our credit facility by an additional amount not to exceed $500.0 million and (2) subject to certain conditions and the consent of the requisite lenders, on two separate occasions extend the maturity date of our credit facility by one year on each occasion. Our credit facility contains certain financial, operational and legal covenants. Among other things, these covenants include maintaining a ratio of consolidated indebtedness to consolidated EBITDA (which is defined in our credit facility and includes projected EBITDA from certain capital expansion projects) of no more than 5.0 to 1.0. If we consummate one or more acquisitions in which the aggregate purchase price is $50.0 million or more, we can elect to increase the

ENLINK MIDSTREAM PARTNERS, LP
Notes to Consolidated Financial Statements (Continued)

maximum allowed ratio of consolidated indebtedness to consolidated EBITDA to 5.5 to 1.0 for the quarter of the acquisition and the three following quarters.

Borrowings under our credit facility bear interest at our option at the Eurodollar Rate (the LIBOR Rate) plus an applicable margin (ranging from 1.00% to 1.75%) or the Base Rate (the highest of the Federal Funds Rate plus 0.50%, the 30-day Eurodollar Rate plus 1.0% or the administrative agent's prime rate) plus an applicable margin (ranging from zero percent to 0.75%). The applicable margins vary depending on our credit rating. If we breach certain covenants governing our credit facility, amounts outstanding under our credit facility, if any, may become due and payable immediately. At December 31, 2016, we were in compliance and expect to be in compliance with the covenants in the existing credit facility for at least the next twelve months.

As of December 31, 2016, there were $11.5 million in outstanding letters of credit and $120.0 million in outstanding borrowings under our credit facility, leaving approximately $1.4 billion available for future borrowing based on the borrowing capacity of $1.5 billion.

Senior Unsecured Notes

On March 7, 2014, we recorded $196.5 million in aggregate principal amount of 7.125% senior unsecured notes (the "2022 Notes") due on June 1, 2022 in the Business Combination. The interest payments on the 2022 Notes are due semi-annually in arrears in June and December. As a result of the Business Combination, the 2022 Notes were recorded at fair value in accordance with acquisition accounting at an amount of $226.0 million, including a premium of $29.5 million. On July 20, 2014, we redeemed $18.5 million aggregate principal amount of the 2022 Notes for $20.0 million, including accrued interest. On September 20, 2014, we redeemed an additional $15.5 million aggregate principal amount of the 2022 Notes for $17.0 million, including accrued interest. We recorded a gain on extinguishment of debt related to the redemption of the 2022 Notes of $2.4 million for the year ended December 31, 2014.

On March 19, 2014, we issued $1.2 billion aggregate principal amount of unsecured senior notes, consisting of $400.0 million aggregate principal amount of our 2.700% senior notes due 2019 (the "2019 Notes"), $450.0 million aggregate principal amount of our 4.400% senior notes due 2024 (the "2024 Notes") and $350.0 million aggregate principal amount of our 5.600% senior notes due 2044 (the "2044 Notes"), at prices to the public of 99.850%, 99.830% and 99.925%, respectively, of their face value. The 2019 Notes mature on April 1, 2019; the 2024 Notes mature on April 1, 2024; and the 2044 Notes mature on April 1, 2044. The interest payments on the 2019 Notes, 2024 Notes and 2044 Notes are due semi-annually in arrears in April and October.

On November 12, 2014, we issued an additional $100.0 million aggregate principal amount of 2024 Notes and $300.0 million aggregate principal amount of our 5.050% senior notes due 2045 (the "2045 Notes"), at prices to the public of 104.007% and 99.452%, respectively, of their face value. The new 2024 Notes were offered as an additional issue of our outstanding 4.400% Senior Notes due 2024, issued in an aggregate principal amount of $450.0 million on March 19, 2014. The 2024 Notes issued on March 19, 2014 and November 12, 2014 are treated as a single class of debt securities and have identical terms, other than the issue date. The 2045 Notes mature on April 1, 2045, and interest payments on the 2045 Notes are due semi-annually in arrears in April and October.

On May 12, 2015, we issued $900.0 million aggregate principal amount of unsecured senior notes, consisting of $750.0 million aggregate principal amount of its 4.150% senior notes due 2025 (the "2025 Notes") and an additional $150.0 million aggregate principal amount of 2045 Notes at prices to the public of 99.827% and 96.381%, respectively, of their face value. The 2025 Notes mature on June 1, 2025. Interest payments on the 2025 Notes are due semi-annually in arrears in June and December. The new 2045 Notes were offered as an additional issue of our outstanding 5.050% Senior Notes due 2045, issued in an aggregate principal amount of $300.0 million on November 12, 2014. The 2045 Notes issued on November 12, 2014 and May 12, 2015 are treated as a single class of debt securities and have identical terms, other than the issue date.

On July 14, 2016, we issued $500.0 million in aggregate principal amount of our 4.850% senior notes due 2026 (the "2026 Notes") at a price to the public of 99.859% of their face value. The 2026 Notes mature on July 15, 2026. Interest payments on the 2026 Notes are payable on January 15 and July 15 of each year, beginning January 15, 2017. Net proceeds of approximately $495.7 million were used to repay outstanding borrowings under our revolving credit facility and for general partnership purposes.

Prior to June 1, 2017, we may redeem all or part of the remaining 2022 Notes at the redemption price equal to the sum of the principal amount thereof, plus a make-whole premium at the redemption date, plus accrued and unpaid interest to the redemption date. On or after June 1, 2017, we may redeem all or a part of the remaining 2022 Notes at redemption prices (expressed as percentages of principal amount) equal to 103.563% for the twelve-month period beginning on June 1, 2017, 102.375% for the twelve-month period beginning on June 1, 2018, 101.188% for the twelve-month period beginning on June 1, 2019 and 100.000% for the twelve-month period beginning on June 1, 2020 and at any time thereafter, plus accrued and unpaid interest, if any, to the applicable redemption date on the 2022 Notes.

Prior to March 1, 2019, we may redeem all or a part of the 2019 Notes at a redemption price equal to the greater of: (i) 100% of the principal amount of the 2019 Notes to be redeemed; or (ii) the sum of the remaining scheduled payments of principal and interest on the 2019 Notes to be redeemed that would be due after the related redemption date but for such redemption (exclusive of interest accrued to, but excluding, the redemption date) discounted to the redemption date on a semi-annual basis (assuming a 360-day year consisting of twelve 30-day months) at the applicable Treasury Rate plus 20 basis points; plus accrued and unpaid interest to, but excluding, the redemption date. At any time on or after March 1, 2019, we may redeem all or a part of the 2019 Notes at a redemption price equal to 100% of the principal amount of the 2019 Notes to be redeemed plus accrued and unpaid interest to, but excluding, the redemption date.

Prior to January 1, 2024, we may redeem all or a part of the 2024 Notes at a redemption price equal to the greater of: (i) 100% of the principal amount of the 2024 Notes to be redeemed; or (ii) the sum of the present values of the remaining scheduled payments of principal and interest on the 2024 Notes to be redeemed that would be due after the related redemption date but for such redemption (exclusive of interest accrued to, but excluding, the redemption date) discounted to the redemption date on a semi-annual basis (assuming a 360-day year consisting of twelve 30-day months) at the applicable Treasury Rate plus 25 basis points; plus accrued and unpaid interest to, but excluding, the redemption date. At any time on or after January 1, 2024, we may redeem all or a part of the 2024 Notes at a redemption price equal to 100% of the principal amount of the 2024 Notes to be redeemed plus accrued and unpaid interest to, but excluding, the redemption date.

Prior to March 1, 2025, we may redeem all or part of the 2025 Notes at a redemption price equal to the greater: (i) 100% of the principal amount of the 2025 Notes to be redeemed; or (ii) the sum of the present values of the remaining scheduled payments of principal and interest on the 2025 Notes to be redeemed that would be due if the 2025 Notes matured on March 1, 2025 (exclusive of interest accrued to, but excluding, the redemption date) discounted to the redemption date on a semi-annual basis (assuming a 360-day year consisting of twelve 30-day months) at the applicable Treasury Rate plus 30 basis points; plus, in either case, accrued and unpaid interest to, but excluding, the redemption date. At any time on or after March 1, 2025, we may redeem all or part of the 2025 Notes at a redemption price equal to the greater, in whole or in part, at a redemption price equal to 100% of the principal amount of the 2025 Notes to be redeemed plus accrued and unpaid interest to, but excluding, the redemption date.

Prior to April 15, 2026, we may redeem all or part of the 2026 Notes at a redemption price equal to the greater: (i) 100% of the principal amount of the 2026 Notes to be redeemed; or (ii) the sum of the present values of the remaining scheduled payments of principal and interest on the 2026 Notes to be redeemed that would be due if the 2026 Notes matured on April 15, 2026 (exclusive of interest accrued to, but excluding, the redemption date) discounted to the redemption date on a semi-annual basis (assuming a 360-day year consisting of twelve 30-day months) at the applicable Treasury Rate plus 50 basis points; plus, in either case, accrued and unpaid interest to, but excluding, the redemption date. At any time on or after April 15, 2026, we may redeem all or part of the 2026 Notes at a redemption price equal to the greater, in whole or in part, at a redemption price equal to 100% of the principal amount of the 2026 Notes to be redeemed plus accrued and unpaid interest to, but excluding, the redemption date.

Prior to October 1, 2043, we may redeem all or a part of the 2044 Notes at a redemption price equal to the greater of: (i) 100% of the principal amount of the 2044 Notes to be redeemed; or (ii) the sum of the present values of the remaining scheduled payments of principal and interest on the 2044 Notes to be redeemed that would be due after the related redemption date but for such redemption (exclusive of interest accrued to, but excluding, the redemption date) discounted to the redemption date on a semi-annual basis (assuming a 360-day year consisting of twelve 30-day months) at the applicable Treasury Rate plus 30 basis points; plus accrued and unpaid interest to, but excluding, the redemption date. At any time on or after October 1, 2043, we may redeem all or a part of the 2044 Notes at a redemption price equal to 100% of the principal amount of the 2044 Notes to be redeemed plus accrued and unpaid interest to, but excluding, the redemption date.

Prior to October 1, 2044, we may redeem all or a part of the 2045 Notes at a redemption price equal to the greater of: (i) 100% of the principal amount of the 2045 Notes to be redeemed; or (ii) the sum of the present values of the remaining scheduled payments of principal and interest on the 2045 Notes to be redeemed that would be due after the related redemption date but for such redemption (exclusive of interest accrued to, but excluding, the redemption date) discounted to the redemption date on a semi-annual basis (assuming a 360-day year consisting of twelve 30-day months) at the applicable Treasury Rate plus 30 basis points; plus accrued and unpaid interest to, but excluding, the redemption date. At any time on or after October 1, 2044, we may redeem all or a part of the 2045 Notes at a redemption price equal to 100% of the principal amount of the 2045 Notes to be redeemed plus accrued and unpaid interest to, but excluding, the redemption date.

The indentures governing the Senior Notes contain covenants that, among other things, limit our ability to create or incur certain liens or consolidate, merge or transfer all or substantially all of our assets.

Each of the following is an event of default under the indentures:

- failure to pay any principal or interest when due;
- failure to observe any other agreement, obligation or other covenant in the indenture, subject to the cure periods for certain failures; and
- bankruptcy or other insolvency events involving us.

If an event of default relating to bankruptcy or other insolvency events occurs, the Senior Notes will immediately become due and payable. If any other event of default exists under the indenture, the trustee under the indenture or the holders of the Senior Notes may accelerate the maturity of the Senior Notes and exercise other rights and remedies. At December 31, 2016 we were in compliance and expect to be in compliance with the covenants in the Senior Notes for at least the next twelve months.

(7) Income Taxes

The components of the provision for income tax expense (benefit) are as follows (in millions):

	Year Ended December 31,		
	2016	2015	2014
Current income tax expense	$ 1.9	$ 3.1	$ 6.7
Deferred tax expense (benefit)	(0.6)	(3.6)	15.3
Total income tax expense (benefit)	$ 1.3	$ (0.5)	$ 22.0

Net income for financial statement purposes may differ significantly from taxable income of unitholders because of differences between the tax basis and financial reporting basis of assets and liabilities and the taxable income allocation requirements under our partnership agreement. The aggregate difference in the basis of our net assets for financial and tax reporting purposes cannot be readily determined because information regarding each partner’s tax attributes is not available to us.

Prior to the Business Combination on March 7, 2014, the Predecessor’s historical combined financial statements include U.S. federal and state income tax expense. As a result of the Business Combination, the Predecessor was reorganized, and Midstream Holdings is treated as a partnership and not subject to federal or certain state income taxes.

Deferred tax liabilities of $73.0 million and $73.6 million existed at December 31, 2016 and 2015, respectively. Deferred tax liabilities as of both December 31, 2016 and 2015 included $63.1 million related to the legacy Partnership’s wholly-owned corporate entity that was formed to acquire the common stock of Clearfield Energy, Inc. This deferred tax liability represents the future tax payable on the difference between the fair value and the carryover tax basis of the assets acquired and is expected to become payable no later than 2027.

As of December 31, 2016, there was no recorded unrecognized tax benefit. A reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows (in millions):

	Year Ended December 31,		
	2016	2015	2014
Beginning Balance, January 1	$ 1.5	$ 2.0	$ —
Unrecognized tax positions assumed in merger	—	—	3.8
Decrease due to prior year tax positions	(1.5)	(0.5)	(2.0)
Increases due to current year tax positions	—	—	0.2
Ending Balance, December 31	$ —	$ 1.5	$ 2.0

There were no unrecognized tax benefits as of December 31, 2016.

Per our accounting policy election, penalties and interest related to unrecognized tax benefits are recorded to income tax expense. As of December 31, 2016, tax years 2012 through 2016 remain subject to examination by various taxing authorities.

(8) Partners' Capital

(a) Issuance of Common Units

In November 2014, we issued 12,075,000 common units representing our limited partner interests at an offering price of $28.37 per unit for net proceeds of $332.3 million. The net proceeds from the common units offering were used for capital expenditures and general partnership purposes.

In October 2014, we issued 1,016,322 common units to ENLC representing our limited partner interests as partial consideration for the E2 acquisition.

In May 2014, we entered into an Equity Distribution Agreement (the "EDA") with BMO Capital Markets Corp. ("BMOCM"). Pursuant to the terms of the EDA, we may from time to time through BMOCM, as our sales agent, sell common units representing limited partner interests having an aggregate offering price of up to $75.0 million. Through December 31, 2014, we sold an aggregate of 2.4 million common units under the EDA, generating proceeds of approximately $71.9 million (net of approximately $0.7 million of commissions to BMOCM). We used the net proceeds for general partnership purposes.

In November 2014, we entered into an Equity Distribution Agreement (the "BMO EDA") with BMO Capital Markets Corp., Merrill Lynch, Pierce, Fenner & Smith Incorporated, Citigroup Global Markets Inc., Jefferies LLC, Raymond James & Associates, Inc. and RBC Capital Markets, LLC (collectively, the "Sales Agents") to sell up to $350.0 million in aggregate gross sales of our common units representing limited partner interests from time to time through an "at the market" equity offering program. We may also sell common units to any Sales Agent as principal for the Sales Agent's own account at a price agreed upon at the time of sale. We have no obligation to sell any of the common units under the BMO EDA and may at any time suspend solicitation and offers under the BMO EDA. For the year ended December 31, 2014, we sold an aggregate of 0.3 million common units under the BMO EDA, generating proceeds of approximately $7.9 million (net of approximately $0.1 million of commissions). For the year ended December 31, 2015, we sold an aggregate of 1.3 million common units under the BMO EDA, generating proceeds of approximately $24.7 million (net of approximately $0.3 million of commissions). For the year ended December 31, 2016, we sold an aggregate of 10.0 million common units under the BMO EDA, generating proceeds of approximately $167.5 million (net of approximately $1.7 million of commissions). We used the net proceeds for general partnership purposes. As of December 31, 2016, approximately $147.8 million of gross common unit issuances remain available to be issued under the BMO EDA.

ENLINK MIDSTREAM PARTNERS, LP
Notes to Consolidated Financial Statements (Continued)

On October 29, 2015, we issued 2,849,100 common units at an offering price of $17.55 per unit to a subsidiary of ENLC for aggregate consideration of approximately $50.0 million in a private placement transaction.

(b) Class C Common Units

In March 2015, we issued 6,704,285 Class C Common Units representing a new class of limited partner interests as partial consideration for the acquisition of Coronado. The Class C Common Units were substantially similar in all respects to our common units, except that distributions paid on the Class C Common Units could be paid in cash or in additional Class C Common Units issued in kind, as determined by our general partner in its sole discretion. Distributions on the Class C Common Units for the three months ended March 31, 2015, June 30, 2015, and September 30, 2015 were paid-in-kind through the issuance of 99,794, 120,622, and 150,732 Class C Common Units on May 14, 2015, August 13, 2015, and November 12, 2015, respectively.Distributions on the Class C Common Units for the three months ended December 31, 2015 and March 31, 2016 were paid-in-kind through the issuance of 209,044 and 233,107 Class C Common Units on February 11, 2016 and May 12, 2016, respectively. All of the outstanding Class C Common Units were converted into common units on a one-for-one basis on May 13, 2016.

(c) Class D Common Units

In February 2015, we issued 31,618,311 Class D Common Units to a wholly-owned subsidiary of ENLC as consideration for a 25% interest in Midstream Holdings. For further discussion see “Note 3—Acquisitions.” Our Class D Common Units were substantially similar in all respects to our common units, except that they only received a pro rata distribution from the date of issuance for the fiscal quarter ended March 31, 2015. Our Class D Common Units automatically converted into our common units on a one-for-one basis on May 4, 2015.

(d) Class E Common Units

In May 2015, we issued 36,629,888 Class E Common Units to a wholly-owned subsidiary of ENLC as consideration for the remaining 25% interest in Midstream Holdings. For further discussion, see “Note 3—Acquisitions.” Our Class E Common Units were substantially similar in all respects to our common units, except that they only received a pro rata distribution from the date of issuance for the fiscal quarter ended June 30, 2015. Our Class E Common Units automatically converted into our common units on a one-for-one basis on August 3, 2015.

(e) Preferred Units

In January 2016, we issued an aggregate of 50,000,000 Series B Cumulative Convertible Preferred Units (the “Preferred Units”) representing our limited partner interests to Enfield Holdings, L.P. (“Enfield”) in a private placement for a cash purchase price of $15.00 per Preferred Unit (the “Issue Price”), resulting in net proceeds of approximately $724.1 million after fees and deductions. Proceeds from the private placement were used to partially fund our portion of the purchase price payable in connection with the EnLink Oklahoma T.O. acquisition. Affiliates of the Goldman Sachs Group, Inc. and affiliates of TPG Global, LLC own interests in the general partner of Enfield. The Preferred Units are convertible into our common units on a one-for-one basis, subject to certain adjustments, at any time after the record date for the quarter ending June 30, 2017 (a) in full, at our option, if the volume weighted average price of a common unit over the 30-trading day period ending two trading days prior to the conversion date (the “Conversion VWAP”) is greater than 150% of the Issue Price or (b) in full or in part, at Enfield’s option. In addition, upon certain events involving a change of control of our general partner or the managing member of ENLC, all of the Preferred Units will automatically convert into a number of common units equal to the greater of (i) the number of common units into which the Preferred Units would then convert and (ii) the number of Preferred Units to be converted multiplied by an amount equal to (x) 140% of the Issue Price divided by (y) the Conversion VWAP.

As a holder of Preferred Units, Enfield is entitled to receive a quarterly distribution, subject to certain adjustments, equal to (x) during the quarter ending March 31, 2016 through the quarter ending June 30, 2017, an annual rate of 8.5% on the Issue Price payable in-kind in the form of additional Preferred Units and (y) thereafter, an annual rate of 7.5% on the Issue Price payable in cash (the “Cash Distribution Component”) plus an in-kind distribution equal to the greater of

ENLINK MIDSTREAM PARTNERS, LP
Notes to Consolidated Financial Statements (Continued)

(A) an annual rate of 1.0% of the Issue Price and (B) an amount equal to (i) the excess, if any, of the distribution that would have been payable had the Preferred Units converted into common units over the Cash Distribution Component, divided by (ii) the Issue Price. Distributions on the Preferred Units for the three months ended March 31, 2016, June 30, 2016 and September 30,2016, were paid-in kind through the issuance of 992,445, 1,083,589, and 1,106,616 Preferred Units on May 12, 2016, August 11, 2016, and November 10, 2016, respectively. A distribution on the Preferred Units was declared for the three months ended December 31, 2016, which will result in the issuance of 1,130,131 additional Preferred Units on February 13, 2016. Income was allocated to the Preferred Units in an amount equal to the quarterly distribution with respect to the period earned. For the year ended December 31, 2016, $69.9 million of income was allocated to the Preferred Units.

(f) Distributions

Unless restricted by the terms of our credit facility and/or the indentures governing our unsecured senior notes, we must make distributions of 100% of available cash, as defined in the partnership agreement, within 45 days following the end of each quarter. Distributions are made to the general partner in accordance with its current percentage interest with the remainder to the common unitholders, subject to the payment of incentive distributions as described below to the extent that certain target levels of cash distributions are achieved. The general partner was not entitled to its general partner or incentive distributions with respect to the Class C Common Units issued in kind. In addition, the general partner is not entitled to its general partner or incentive distributions with respect to the Preferred Units until conversion to common units.

Our general partner owns the general partner interest in us and all of our incentive distribution rights. Our general partner is entitled to receive incentive distributions if the amount we distribute with respect to any quarter exceeds levels specified in our partnership agreement. Under the quarterly incentive distribution provisions, our general partner is entitled to 13.0% of amounts we distribute in excess of $0.25 per unit, 23% of the amounts we distribute in excess of $0.3125 per unit and 48.0% of amounts we distribute in excess of $0.375 per unit.

A summary of the distribution activity relating to the common units for the years ended December 31, 2016, 2015 and 2014 is provided below:

Declaration period	Distribution/unit		Date paid/payable
2016			
First Quarter of 2016	$	0.390	May 12, 2016
Second Quarter of 2016	$	0.390	August 11, 2016
Third Quarter of 2016	$	0.390	November 11, 2016
Fourth Quarter of 2016	$	0.390	February 13, 2017
2015			
First Quarter of 2015 (1)	$	0.380	May 14, 2015
Second Quarter of 2015 (2)	$	0.385	August 13, 2015
Third Quarter of 2015	$	0.390	November 12, 2015
Fourth Quarter of 2015	$	0.390	February 11, 2016
2014			
First Quarter of 2014 (3)	$	0.360	May 14, 2014
Second Quarter of 2014	$	0.365	August 13, 2014
Third Quarter of 2014	$	0.370	November 13, 2014
Fourth Quarter of 2014	$	0.375	February 12, 2015

(1) Our partial first quarter 2015 distributions on our Class D Common Units of $0.18 per unit were paid on May 14, 2015. Distributions paid for the Class D Common Units represent a pro rata distribution for the number of days the Class D Common Units were issued and outstanding during the quarter. The Class D Common Units automatically converted into common units on a one-for-one basis on May 4, 2015.

ENLINK MIDSTREAM PARTNERS, LP
Notes to Consolidated Financial Statements (Continued)

(2) Our partial second quarter 2015 distributions on our Class E Common Units of $0.15 per unit were paid on August 13, 2015. Distributions paid for the Class E Common Units represent a pro rata distribution for the number of days the Class E Common Units were issued and outstanding during the quarter. The Class E Common Units automatically converted into common units on a one-for-one basis on August 3, 2015.
(3) Our first quarter 2014 distributions on our Class B Common Units of $0.10 per unit were paid on May 14, 2014. Distributions declared for the Class B Common Units represent a pro rata distribution for the number of days the Class B Common Units were issued and outstanding during the quarter. The Class B Common Units automatically converted into common units on a one-for-one basis on May 6, 2014.

(g) Earnings per Unit and Dilution Computations

As required under ASC 260, Earnings Per Share, unvested share-based payments that entitle employees to receive non-forfeitable distributions are considered participating securities for earnings per unit calculations. Net income earned by the Predecessor prior to March 7, 2014 is not included for purposes of calculating earnings per unit as the Predecessor did not have any unitholders. Net income (loss) attributable to the EMH Drop Downs and VEX Interests acquired from ENLC and Devon, respectively, for periods prior to acquisition is not allocated to the limited partners for purposes of calculating net income (loss) per common unit. The following table reflects the computation of basic and diluted earnings per limited partner units for the periods presented (in millions except per unit amounts):

	Year Ended December 31,		
	2016	2015	2014 (1)
Limited partners' interest in net income (loss)	$ (662.1)	$ (1,405.2)	$ 136.7
Distributed earnings allocated to:			
Common units (2)	$ 520.0	$ 465.9	$ 310.0
Unvested restricted units (2)	3.5	2.0	1.3
Total distributed earnings	$ 523.5	$ 467.9	$ 311.3
Undistributed loss allocated to:			
Common units	$ (1,177.6)	$ (1,865.3)	$ (173.9)
Unvested restricted units	(8.0)	(7.8)	(0.7)
Total undistributed loss	$ (1,185.6)	$ (1,873.1)	$ (174.6)
Net income (loss) allocated to:			
Common units	$ (657.6)	$ (1,399.4)	$ 136.1
Unvested restricted units	(4.5)	(5.8)	0.6
Total limited partners' interest in net income (loss)	$ (662.1)	$ (1,405.2)	$ 136.7
Basic and diluted net income (loss) per unit:			
Basic	$ (1.99)	$ (4.66)	$ 0.59
Diluted	$ (1.99)	$ (4.66)	$ 0.59

(1) The 2014 amounts consist only of the period from March 7, 2014 through December 31, 2014.
(2) Represents distribution activity consistent with the declarations disclosed in section "(f) Distributions" above.

The following are the unit amounts used to compute the basic and diluted earnings per limited partner unit for the years ended December 31, 2016, 2015 and 2014 (in millions):

	Year Ended December 31,		
	2016	2015	2014 (1)
Basic weighted average units outstanding:			
Weighted average limited partner basic common units outstanding (2)	333.3	301.6	232.8
Diluted weighted average units outstanding:	—	5.5	—
Weighted average limited partner basic common units outstanding	333.3	307.1	232.8
Dilutive effect of restricted units issued	—	—	0.4
Total weighted average limited partner diluted common units outstanding	333.3	307.1	233.2

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Notes to Consolidated Financial Statements (Continued)

(1) The year ended December 31, 2014 amounts consist only of the period from March 7, 2014 through September 30, 2014.
(2) The years ended December 31, 2016 and 2015 common units include the weighted average impact of 2,740,273 and 5,459,905 Class C Units, respectively, which converted into common units on May 13, 2016. The year ended December 31, 2015 common units include the weighted average impact of 6,670,164 and 6,924,554 Class D and E units, respectively. The Class D and E units converted on May 4, 2015 and August 3, 2015, respectively.

All outstanding units were included in the computation of diluted earnings per unit and weighted based on the number of days such units were outstanding during the period presented. All common unit equivalents were antidilutive for the years ended December 31, 2016 and 2015 because the limited partners were allocated a net loss.

Net income is allocated to the general partner in an amount equal to its incentive distribution rights as described in section "(f) Distributions" above. The general partner's share of net income consists of incentive distribution rights to the extent earned, a deduction for unit-based compensation attributable to ENLC's restricted units, the percentage interest of our net income adjusted for ENLC's unit-based compensation specifically allocated to the general partner and net income attributable to the drop down transactions described in "Note 3—Acquisitions." The net income allocated to the general partner is as follows (in millions):

	Year Ended December 31,		
	2016	2015	2014 (1)
Income allocation for incentive distributions	$ 56.8	$ 47.5	$ 20.6
Unit-based compensation attributable to ENLC's restricted units	(14.7)	(18.3)	(10.4)
General partner share of net income (loss)	(2.6)	(6.7)	1.1
General partner interest in drop down transactions	—	35.5	127.0
General partner interest in net income	$ 39.5	$ 58.0	$ 138.3

(1) The year ended December 31, 2014 amounts consist only of the period from March 7, 2014 through December 31, 2014.

(9) Asset Retirement Obligations

The schedule below summarizes the changes in our asset retirement obligations (in millions):

	Year Ended December 31,	
	2016	2015
Beginning asset retirement obligations	$ 14.0	$ 20.6
Revisions to the fair values of existing liabilities	(0.5)	(4.0)
Accretion expense	0.6	0.6
Liabilities settled	(0.6)	(3.2)
Ending asset retirement obligations	$ 13.5	$ 14.0

Asset retirement obligations of $13.5 million and $12.9 million were included in "Asset retirement obligations" as noncurrent liabilities on the consolidated balance sheets as of December 31, 2016 and 2015, respectively. Asset retirement obligations of $1.1 million were included in "Other current liabilities" on the consolidated balance sheet as of December 31, 2015. There were no asset retirement obligations included in "Other current liabilities" on the consolidated balance sheet as of December 31, 2016.

(10) Investments in Unconsolidated Affiliates

Our unconsolidated investments consisted of:

- a contractual right to the benefits and burdens associated with Devon's 38.75% ownership interest in GCF at December 31, 2016, 2015 and 2014;
- an approximate 31% ownership interest in HEP at December 31, 2016, 2015 and 2014; and
- a 30.0% ownership in the Cedar Cove JV at December 31, 2016.

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Notes to Consolidated Financial Statements (Continued)

In December 2016, we entered into an agreement to sell our ownership interest in HEP for approximately $193.1 million, subject to customary closing conditions, including regulatory approvals. We expect the transaction to close in the first quarter of 2017. For the year ended December 31, 2016, we recorded an impairment of $20.1 million to reduce the carrying value of our investment to the expected sales price.

The following table shows the activity related to our investment in unconsolidated affiliates for the periods indicated (in millions):

	Gulf Coast Fractionators	Howard Energy Partners	Cedar Cove JV	Total
December 31, 2016				
Contributions (1)	$ —	$ 45.0	$ 28.8	$ 73.8
Distributions (2)	$ 7.5	$ 50.2	$ —	$ 57.7
Equity in income (3)	$ 3.4	$ (23.3)	$ —	$ (19.9)
December 31, 2015				
Contributions	$ —	$ 25.8	$ —	$ 25.8
Distributions	$ 14.5	$ 28.2	$ —	$ 42.7
Equity in income	$ 13.0	$ 7.4	$ —	$ 20.4
December 31, 2014 (4)				
Contributions	$ —	$ 5.7	$ —	$ 5.7
Distributions	$ 11.0	$ 12.7	$ —	$ 23.7
Equity in income	$ 17.1	$ 1.8	$ —	$ 18.9

(1) Contributions for the year ended December 31, 2016 include $32.7 million of contributions to HEP for preferred units through July 2016. These preferred units were redeemed during the third quarter 2016.
(2) Distributions for the year ended December 31, 2016 include a redemption of $32.7 million of preferred units.
(3) Includes a $20.1 million impairment in our HEP investment to reduce the carrying value of our investment to the sales price that we expect to receive in the first quarter of 2017.
(4) Includes income, distributions and contributions for the period from March 7, 2014 through December 31, 2014.

The following table shows the balances related to our investment in unconsolidated affiliates for the periods indicated (in millions):

	Year Ended December 31, 2016	2015
Gulf Coast Fractionators	$ 48.5	$ 52.6
Howard Energy Partners (1)	193.1	221.7
Cedar Cove JV	28.8	—
Total investments in unconsolidated affiliates	$ 270.4	$ 274.3

(1) Due to the expected completion of the sale of our investment in HEP in the first quarter of 2017, the HEP investment balance is classified as "Investment in unconsolidated affiliates – current" on the consolidated balance sheet as of December 31, 2016.

(11) Employee Incentive Plans

(a) Long-Term Incentive Plans

We account for unit-based compensation in accordance with ASC 718, *Stock Compensation* ("ASC 718"), which requires that compensation related to all unit-based awards, including unit options, be recognized in the consolidated financial statements. Effective April 6, 2016, our unitholders approved the amended and restated the EnLink Midstream GP, LLC Long-Term Incentive Plan (the "GP Plan"). This amendment and restatement to the GP Plan included an increase to the number of common units authorized for issuance under the GP Plan by 5,000,000 common units to an aggregate of 14,070,000 common units and other technical changes.

We and ENLC each have similar unit-based compensation payment plans for officers and employees, which are described below. Unit-based compensation associated with ENLC's unit-based compensation plan awarded to our officers and employees are recorded by us since ENLC has no substantial or managed operating activities other than its interests in us and EnLink Oklahoma T.O. Amounts recognized in the consolidated financial statements with respect to these plans are as follows (in millions):

	Year Ended December 31,		
	2016	2015	2014
Cost of unit-based compensation allocated to Predecessor general and administrative expense (1)	$ —	$ —	$ 2.8
Cost of unit-based compensation charged to general and administrative expense	23.4	30.7	16.7
Cost of unit-based compensation charged to operating expense	6.6	5.0	2.7
Total amount charged to income	$ 30.0	$ 35.7	$ 22.2

(1) Unit-based compensation expense was treated as a contribution by the Predecessor in the consolidated statements of changes in member's equity for the year ended December 31, 2014.

(b) EnLink Midstream Partners, LP's Restricted Incentive Units

The restricted incentive units are valued at their fair value at the date of grant, which is equal to the market value of common units on such date. A summary of the restricted incentive unit activity for the year ended December 31, 2016 is provided below:

	Year Ended December 31, 2016	
EnLink Midstream Partners, LP Restricted Incentive Units:	**Number of Units**	**Weighted Average Grant-Date Fair Value**
Non-vested, beginning of period	1,253,729	$ 29.59
Granted	1,149,105	10.71
Vested (1)	(316,677)	30.08
Forfeited	(61,337)	21.23
Non-vested, end of period	2,024,820	$ 19.05
Aggregate intrinsic value, end of period (in millions)	$ 37.3	

(1) Vested units include 91,110 units withheld for payroll taxes paid on behalf of employees.

A summary of the restricted incentive units' aggregate intrinsic value (market value at vesting date) and fair value of units vested (market value at date of grant) during the years ended December 31, 2016 and 2015 are provided below (in millions):

	Year Ended December 31,	
EnLink Midstream Partners, LP Restricted Incentive Units:	**2016**	**2015**
Aggregate intrinsic value of units vested	$ 4.1	$ 7.5
Fair value of units vested	$ 9.5	$ 8.1

As of December 31, 2016, there was $13.9 million of unrecognized compensation cost related to Partnership non-vested restricted incentive units. That cost is expected to be recognized over a weighted-average period of 1.7 years.

(c) EnLink Midstream Partners, LP's Performance Units

In 2015 and 2016, our general partner and the managing member of ENLC granted performance awards under the GP Plan and the EnLink Midstream, LLC 2014 Long-Term Incentive Plan (the "2014 Plan"), respectively. The performance award agreements provide that the vesting of restricted incentive units granted thereunder is dependent on the achievement of certain total shareholder return ("TSR") performance goals relative to the TSR achievement of a peer group of companies (the "Peer Companies") over the applicable performance period. The performance award agreements contemplate that the Peer Companies for an individual performance award (the "Subject Award") are the companies comprising the Alerian MLP Index for Master Limited Partnerships ("AMZ"), excluding us and ENLC (collectively, "EnLink"), on the grant date for the Subject Award. The performance units will vest based on the percentile ranking of the average of our and ENLC's TSR achievement ("EnLink TSR") for the applicable performance period relative to the TSR achievement of the Peer Companies.

At the end of the vesting period, recipients receive distribution equivalents, if any, with respect to the number of performance units vested. The vesting of EnLink Midstream Partners, LP's performance units range from zero to 200% of the units granted depending on the EnLink TSR as compared to the Peer Companies on the vesting date. The fair value of each performance unit is estimated as of the date of grant using a Monte Carlo simulation with the following assumptions used for all performance unit grants made under the 2014 Plan: (i) a risk-free interest rate based on United States Treasury rates as of the grant date; (ii) a volatility assumption based on the historical realized price volatility of our common units and the designated peer group securities; (iii) an estimated ranking of us among the designated peer group; and (iv) the distribution yield. The fair value of the performance unit on the date of grant is expensed over a vesting period of approximately three years. The following table presents a summary of the grant-date fair values of performance units granted and the related assumptions:

EnLink Midstream Partners, LP Performance Units:	Beginning TSR Price	Risk-free interest rate	Volatility factor	Distribution yield
2016				
January 2016	$ 14.82	1.10 %	39.71 %	12.10 %
February 2016	$ 14.82	0.89 %	42.33 %	19.20 %
October 2016	$ 17.71	0.91 %	44.62 %	8.80 %
2015				
March 2015	$ 27.68	0.99 %	33.01 %	5.66 %

The following table presents a summary of our performance units:

EnLink Midstream Partners, LP Performance Units:	Year Ended December 31, 2016 Number of Units	Weighted Average Grant-Date Fair Value
Non-Vested, beginning of period	118,126	$ 35.41
Granted	293,309	11.53
Forfeited	(2,798)	36.18
Non-vested, end of period	408,637	$ 11.53
Aggregate intrinsic value, end of period (in millions)	$ 7.5	

As of December 31, 2016, there was $4.1 million of unrecognized compensation expense that related to non-vested Partnership performance units. That cost is expected to be recognized over a weighted-average period of 1.8 years.

ENLINK MIDSTREAM PARTNERS, LP
Notes to Consolidated Financial Statements (Continued)

(d) EnLink Midstream, LLC's Restricted Incentive Units

On February 5, 2014, ENLC's sole unitholder at the time, EnLink Midstream Manager, LLC, approved the EnLink Midstream, LLC 2014 Long-Term Incentive Plan (the "Company Plan"). The Company Plan provides for the issuance of 11,000,000 ENLC common units.

On March 7, 2014, effective as of the closing of the Business Combination, ENLC (i) assumed the Crosstex Energy, Inc. 2009 Long-Term Incentive Plan (the "2009 Plan") and all awards thereunder outstanding following the Business Combination and (ii) amended and restated the 2009 Plan to reflect the conversion of the awards under the 2009 Plan relating to EMI's common stock to awards in respect of common units of ENLC.

ENLC's restricted incentive units are valued at their fair value at the date of grant which is equal to the market value of the common units on such date. A summary of the restricted incentive unit activities for the year ended December 31, 2016 is provided below:

	Year Ended December 31, 2016	
EnLink Midstream, LLC Restricted Incentive Units:	**Number of Units**	**Weighted Average Grant-Date Fair Value**
Non-vested, beginning of period	1,148,893	$ 34.78
Granted	1,146,067	10.16
Vested (1)	(340,234)	36.55
Forfeited	(57,428)	22.67
Non-vested, end of period	1,897,298	$ 19.96
Aggregate intrinsic value, end of period (in millions)	$ 36.1	

(1) Vested units include 97,087 units withheld for payroll taxes paid on behalf of employees.

A summary of the restricted units' aggregate intrinsic value (market value at vesting date) and fair value of units vested (market value at date of grant) during the years ended December 31, 2016 and 2015 are provided below (in millions):

	Year Ended December 31,	
EnLink Midstream LLC Restricted Incentive Units:	**2016**	**2015**
Aggregate intrinsic value of units vested	$ 4.1	$ 9.2
Fair value of units vested	$ 12.4	$ 9.8

As of December 31, 2016, there was $13.6 million of unrecognized compensation costs related to ENLC non-vested restricted incentive units for directors, officers and employees. The cost is expected to be recognized over a weighted average period of 1.6 years.

(e) EnLink Midstream, LLC's Performance Units

In 2015 and 2016, ENLC granted performance awards under the 2014 Plan discussed in section (c) above. At the end of the vesting period, recipients receive distribution equivalents, if any, with respect to the number of performance units vested. The vesting of units range from zero to 200% of the units granted depending on the EnLink TSR as compared to the TSR of the Peer Companies on the vesting date. The fair value of each performance unit is estimated as of the date of grant using a Monte Carlo simulation with the following assumptions used for all performance unit grants made under the plan: (i) a risk-free interest rate based on United States Treasury rates as of the grant date; (ii) a volatility assumption based on the historical realized price volatility of ENLC's common units and the designated peer group securities; (iii) an estimated ranking of ENLC among the designated peer group and (iv) the distribution yield. The fair value of the unit on the date of grant is expensed over a vesting period of three years. The following table presents a summary of the grant-date fair values of performance units granted and the related assumptions:

EnLink Midstream, LLC Performance Units:	Beginning TSR Price	Risk-free interest rate	Volatility factor	Distribution yield
2016				
January 2016	$ 15.38	1.10 %	46.02 %	8.60 %
February 2016	$ 15.38	0.89 %	52.05 %	14.00 %
October 2016	$ 16.75	0.91 %	52.89 %	6.10 %
2015				
March 2015	$ 34.24	0.99 %	33.02 %	2.98 %

The following table presents a summary of the ENLC's performance units.

	Year Ended December 31, 2016	
EnLink Midstream, LLC Performance Units:	Number of Units	Weighted Average Grant-Date Fair Value
Non-Vested, beginning of period	105,080	$ 40.50
Granted	281,709	11.58
Forfeited	(2,525)	41.31
Non-vested, end of period	384,264	$ 19.30
Aggregate intrinsic value, end of period (in millions)	$ 7.3	

As of December 31, 2016, there was $4.1 million of unrecognized compensation expense that related to non-vested ENLC performance units. That cost is expected to be recognized over a weighted-average period of 1.8 years.

(f) Benefit Plan

We sponsor a single employer 401(k) plan whereby we match 100% of every dollar contributed up to 8% of an employee's salary. Contributions of $7.4 million and $7.0 million were made to the plan for the years ended December 31, 2016 and 2015, respectively.

(12) Derivatives

Interest Rate Swaps

We entered into interest rate swaps in 2016 in connection with the issuance of the 2026 Notes, in 2015 in connection with the issuance of the 2025 Notes, and in 2014 in connection with the issuance of the 2024 Notes and 2045 Notes. We have no open interest rate swap positions as of December 31, 2016.

The impact of the interest rate swaps on net income is included in other income (expense) in the consolidated statements of operations as part of interest expense, net, as follows (in millions):

	Year Ended December 31,		
	2016	2015	2014
Settlement gains on derivatives	$ 0.4	$ 3.6	$ 3.6

ENLINK MIDSTREAM PARTNERS, LP
Notes to Consolidated Financial Statements (Continued)

Commodity Swaps

We manage our exposure to fluctuation in commodity prices by hedging the impact of market fluctuations. Swaps are used to manage and hedge price and location risk related to these market exposures. Swaps are also used to manage margins on offsetting fixed-price purchase or sale commitments for physical quantities of natural gas and NGLs. We do not designate transactions as cash flow or fair value hedges for hedge accounting treatment under ASC 815. Therefore, changes in the fair value of our derivatives are recorded in revenue in the period incurred. In addition, our risk management policy does not allow us to take speculative positions with our derivative contracts.

We commonly enter into index (float-for-float) or fixed-for-float swaps in order to mitigate our cash flow exposure to fluctuations in the future prices of natural gas, NGLs and crude oil. For natural gas, index swaps are used to protect against the price exposure of daily priced gas versus first-of-month priced gas. They are also used to hedge the basis location price risk resulting from supply and markets being priced on different indices. For natural gas, NGLs, condensate and crude, fixed-for-float swaps are used to protect cash flows against price fluctuations: (1) where we receive a percentage of liquids as a fee for processing third-party gas or where we receive a portion of the proceeds of the sales of natural gas and liquids as a fee, (2) in the natural gas processing and fractionation components of our business and (3) where we are mitigating the price risk for product held in inventory or storage.

The components of gain (loss) on derivative activity in the consolidated statements of operations related to commodity swaps are (in millions):

	Year Ended December 31,		
	2016	2015	2014 (1)
Change in fair value of derivatives	$ (20.1)	$ (7.7)	$ 22.4
Realized gain (loss) on derivatives	9.0	17.1	(0.3)
Gain (loss) on derivative activity	$ (11.1)	$ 9.4	$ 22.1

(1) Represents activity from the period between March 7, 2014 to December 31, 2014.

The fair value of derivative assets and liabilities related to commodity swaps are as follows (in millions):

	Year Ended December 31,	
	2016	2015
Fair value of derivative assets - current	$ 1.3	$ 16.8
Fair value of derivative liabilities - current	(7.6)	(2.9)
Fair value of derivative liabilities - long-term	—	(0.1)
Net fair value of derivatives	$ (6.3)	$ 13.8

Assets and liabilities related to our derivative contracts are included in the fair value of derivative assets and liabilities and the change in fair value of these contracts are recorded at net as a gain (loss) on derivative activity in the consolidated statements of operations. We estimate the fair value of all of our derivative contracts using actively quoted prices. The total estimated fair value liability of derivative contracts of $6.3 million as of December 31, 2016 has a maturity date of less than one year.

Set forth below is the summarized notional volumes and fair value of all instruments held for price risk management purposes and related physical offsets at December 31, 2016 (in millions). The remaining term of the contracts extend no later than December 2017.

		December 31, 2016		
Commodity	**Instruments**	**Unit**	**Volume**	**Fair Value**
NGL (short contracts)	Swaps	Gallons	(27.7)	$ (3.8)
NGL (long contracts)	Swaps	Gallons	8.3	0.2
Natural Gas (short contracts)	Swaps	MMBtu	(6.8)	(3.7)
Natural Gas (long contracts)	Swaps	MMBtu	3.5	1.0
Total fair value of derivatives				$ (6.3)

On all transactions where we are exposed to counterparty risk, we analyze the counterparty's financial condition prior to entering into an agreement, establish limits and monitor the appropriateness of these limits on an ongoing basis. We primarily deal with two types of counterparties, financial institutions and other energy companies, when entering into financial derivatives on commodities. We have entered into Master International Swaps and Derivatives Association Agreements ("ISDAs") that allow for netting of swap contract receivables and payables in the event of default by either party. If our counterparties failed to perform under existing swap contracts, our maximum loss of $1.3 million as of December 31, 2016 would be reduced to $0.1 million due to the offsetting of gross fair value payables against gross fair value receivables as allowed by the ISDAs.

(13) Fair Value Measurements

ASC 820, *Fair Value Measurements and Disclosures* ("ASC 820"), sets forth a framework for measuring fair value and required disclosures about fair value measurements of assets and liabilities. Fair value under ASC 820 is defined as the price at which an asset could be exchanged in a current transaction between knowledgeable, willing parties. A liability's fair value is defined as the amount that would be paid to transfer the liability to a new obligor, not the amount that would be paid to settle the liability with the creditor. Where available, fair value is based on observable market prices or parameters or derived from such prices or parameters. Where observable prices or inputs are not available, use of unobservable prices or inputs are used to estimate the current fair value, often using an internal valuation model. These valuation techniques involve some level of management estimation and judgment, the degree of which is dependent on the item being valued.

ASC 820 established a three-tier fair value hierarchy, which prioritizes the inputs used in measuring fair value. These tiers include: Level 1, defined as observable inputs such as quoted prices in active markets; Level 2, defined as inputs other than quoted prices in active markets that are either directly or indirectly observable; and Level 3, defined as unobservable inputs in which little or no market data exists, therefore requiring an entity to develop its own assumptions.

Our derivative contracts primarily consist of commodity swap contracts, which are not traded on a public exchange. The fair values of commodity swap contracts are determined using discounted cash flow techniques. The techniques incorporate Level 1 and Level 2 inputs for future commodity prices that are readily available in public markets or can be derived from information available in publicly quoted markets. These market inputs are utilized in the discounted cash flow calculation considering the instrument's term, notional amount, discount rate and credit risk and are classified as Level 2 in hierarchy.

ENLINK MIDSTREAM PARTNERS, LP
Notes to Consolidated Financial Statements (Continued)

Net assets (liabilities) measured at fair value on a recurring basis are summarized below (in millions):

	Level 2 December 31, 2016	Level 2 December 31, 2015
Commodity Swaps (1)	$ (6.3)	$ 13.8
Total	$ (6.3)	$ 13.8

(1) The fair value of derivative contracts included in assets or liabilities for risk management activities represents the amount at which the instruments could be exchanged in a current arms-length transaction adjusted for credit risk of us and/or the counterparty as required under ASC 820.

Fair Value of Financial Instruments

The estimated fair value of our financial instruments has been determined using available market information and valuation methodologies. Considerable judgment is required to develop the estimates of fair value; thus, the estimates provided below are not necessarily indicative of the amount we could realize upon the sale or refinancing of such financial instruments (in millions):

	December 31, 2016		December 31, 2015	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt (1)	$ 3,268.0	$ 3,225.8	$ 3,066.8	$ 2,585.5
Installment Payables	$ 473.2	$ 476.6	$ —	$ —
Obligations under capital lease	$ 6.6	$ 6.1	$ 16.7	$ 15.6

(1) The carrying values of long-term debt are reduced by debt issuance costs of $24.1 million and $23.0 million at December 31, 2016 and 2015, respectively. The respective fair values do not factor in debt issuance costs.

The carrying amounts of our cash and cash equivalents, accounts receivable, and accounts payable approximate fair value due to the short-term maturities of these assets and liabilities.

We had $120.0 million and $414.0 million in outstanding borrowings under our revolving credit facility as of December 31, 2016 and 2015, respectively. As borrowings under the credit facility accrue interest under floating interest rate structures, the carrying value of such indebtedness approximates fair value for the amounts outstanding under the credit facility. As of December 31, 2016, we had total borrowings of $3.1 billion under senior unsecured notes maturing between 2019 and 2045 with fixed interest rates ranging from 2.7% to 7.1%. As of December 31, 2015, we had total borrowings of $2.7 billion maturing between 2019 and 2045 with fixed interest rates ranging from 2.7% to 7.1%. The fair value of all senior unsecured notes as of December 31, 2016 and 2015 was based on Level 2 inputs from third-party market quotations. The fair value of obligations under capital leases was calculated using Level 2 inputs from third-party banks.

(14) Commitments and Contingencies

(a) Leases—Lessee

We have operating leases for office space, office and field equipment.

ENLINK MIDSTREAM PARTNERS, LP
Notes to Consolidated Financial Statements (Continued)

The following table summarizes our remaining non-cancelable future payments under operating leases with initial or remaining non-cancelable lease terms in excess of one year (in millions):

2017	$ 16.2
2018	15.4
2019	10.9
2020	8.6
2021	8.7
Thereafter	64.0
Total	$ 123.8

Operating lease rental expense was approximately $59.6 million, $66.1 million and $50.8 million for the years ended December 31, 2016, 2015 and 2014, respectively.

(b) Change of Control and Severance Agreements

Certain members of our management are parties to severance and change of control agreements with EnLink Midstream Operating, LP, a Delaware limited partnership (the "Operating Partnership"). The severance and change in control agreements provide those individuals with severance payments in certain circumstances and prohibit such individual from, among other things, competing with the general partner or its affiliates during his or her employment. In addition, the severance and change of control agreements prohibit subject individuals from disclosing confidential information about the general partner or interfering with a client or customer of the general partner or its affiliates, in each case during his or her employment and for certain periods (including indefinite periods) following the termination of such person's employment.

(c) Environmental Issues

The operation of pipelines, plants and other facilities for the gathering, processing, transmitting or disposing of natural gas, NGLs, crude oil, condensate, brine and other products is subject to stringent and complex laws and regulations pertaining to health, safety and the environment. As an owner, partner or operator of these facilities, we must comply with United States laws and regulations at the federal, state and local levels that relate to air and water quality, hazardous and solid waste management and disposal, and other environmental matters. The cost of planning, designing, constructing and operating pipelines, plants, and other facilities must incorporate compliance with environmental laws and regulations and safety standards. Failure to comply with these laws and regulations may trigger a variety of administrative, civil and potentially criminal enforcement measures, including citizen suits, which can include the assessment of monetary penalties, the imposition of remedial requirements, and the issuance of injunctions or restrictions on operation. Management believes that, based on currently known information, compliance with these laws and regulations will not have a material adverse effect on our results of operations, financial condition or cash flows.

As previously disclosed, a spill occurred in our West Virginia operations in the third quarter of 2015. In 2016, all clean-up and subsequent confirmatory sampling of the spill event were completed and analysis of the spilled constituents were below detectible limits. Accordingly, this matter has been completed with no material fine or penalty. Also as previously disclosed, in February 2016, a spill occurred at our Kill Buck Station in our Ohio operations. State and federal agencies were notified and clean-up response efforts were promptly executed, which significantly lessened the impact of the spill. The state agency determined that the clean-up recovery efforts were completed and issued to us a "No Further Action" notice. We do not anticipate a material fine or penalty by either the state or federal agencies.

In the third quarter of 2016, in connection with the transition to our operational control of E2 Appalachian Compression, LLC in and preparation to commence operational control of E2 Ohio Compression, LLC, we discovered instances of noncompliance with air regulations and permits. This noncompliance was self-reported to the Ohio Environmental Protection Agency ("OEPA"), resulting in the issuance of notices of violations ("NOVs"). We have continued to work with OPEA and have taken appropriate measures to achieve compliance with applicable requirements, and, while we do not yet have information concerning any fine or penalty that may be assessed, we do not believe any such fine or penalty will be material to our operations. On July 29, 2016, after concluding a multi-year internal environmental compliance assessment of our Louisiana operations, we made an offer of $0.1 million in the form of a Global Settlement to the Louisiana Department of Environmental Quality ("LDEQ") to resolve environmental noncompliance discovered or investigated during our assessment, which involved several of our Louisiana facilities. The noncompliance proposed to be covered by the Global Settlement include noncompliance that was self-reported to the LDEQ as the result of our assessment as well as noncompliance that was the subject of notices of potential violations and NOVs that we received from the LDEQ during the assessment time frame. We have taken the appropriate measures to resolve the instances of noncompliance, and we will continue to work with the LDEQ with respect to the proposed Global Settlement. Lastly, we continue to work with Pipeline and Hazardous Materials Safety Administration regarding the notice of potential violation in our ORV operations. For more information refer to "Item 1. Business—Environmental Matters."

(d) Litigation Contingencies

We are involved in various litigation and administrative proceedings arising in the normal course of business. In the opinion of management, any liabilities that may result from these claims would not individually or in the aggregate have a material adverse effect on our financial position, results of operations or cash flows.

At times, our subsidiaries acquire pipeline easements and other property rights by exercising rights of eminent domain and common carrier. As a result, from time to time we (or our subsidiaries) are a party to a number of lawsuits under which a court will determine the value of pipeline easements or other property interests obtained by our subsidiaries by condemnation. Damage awards in these suits should reflect the value of the property interest acquired and the diminution in the value of the remaining property owned by the landowner. However, some landowners have alleged unique damage theories to inflate their damage claims or assert valuation methodologies that could result in damage awards in excess of the amounts anticipated. Although it is not possible to predict the ultimate outcomes of these matters, we do not expect that awards in these matters will have a material adverse impact on our consolidated results of operations, financial condition or cash flows.

We (or our subsidiaries) are defending lawsuits filed by owners of property located near processing facilities or compression facilities constructed by us as part of our systems. The suits generally allege that the facilities create a private nuisance and have damaged the value of surrounding property. Claims of this nature have arisen as a result of the industrial development of natural gas gathering, processing and treating facilities in urban and occupied rural areas.

In July 2013, the Board of Commissioners for the Southeast Louisiana Flood Protection Authority for New Orleans and surrounding areas filed a lawsuit against approximately 100 energy companies, seeking, among other relief, restoration of wetlands allegedly lost due to historic industry operations in those areas. The suit was filed in Louisiana state court in New Orleans, but was removed to the United States District Court for the Eastern District of Louisiana. The amount of damages is unspecified. Our subsidiary, EnLink LIG, LLC, is one of the named defendants as the owner of pipelines in the area. On February 13, 2015, the court granted defendants' joint motion to dismiss and dismissed the plaintiff's claims with prejudice. Plaintiffs have appealed the matter to the United States Court of Appeals for the Fifth Circuit. We intend to continue vigorously defending the case. The success of the plaintiffs' appeal as well as our costs and legal exposure, if any, related to the lawsuit are not currently determinable.

We own and operate a high-pressure pipeline and underground natural gas and NGL storage reservoirs and associated facilities near Bayou Corne, Louisiana. In August 2012, a large sinkhole formed in the vicinity of this pipeline and underground storage reservoirs. We are seeking to recover our losses from responsible parties. We have sued Texas Brine Company, LLC ("Texas Brine"), the operator of a failed cavern in the area and its insurers, seeking recovery for these losses. We have also sued Occidental Chemical Company and Legacy Vulcan Corp. f/k/a Vulcan Materials Company, two Chlor-Alkali plant operators that participated in Texas Brine's operational decisions regarding the mining of the failed cavern. We also filed a claim with our insurers, which our insurers denied. We disputed the denial and sued our insurers, but we have agreed to stay the matter pending resolution of our claims against Texas Brine and its insurers. In August 2014, we received a partial settlement with respect to the Texas Brine claims in the amount of $6.1 million, but additional claims remain outstanding. We cannot give assurance that we will be able to fully recover our losses through insurance recovery or claims against responsible parties.

In June 2014, a group of landowners in Assumption Parish, Louisiana added our subsidiary, EnLink Processing Services, LLC, as a defendant in a pending lawsuit they had filed against Texas Brine, Occidental Chemical Corporation, and Vulcan Materials Company relating to claims arising from the Bayou Corne sinkhole. The suit is pending in the 23rd Judicial Court, Assumption Parish, Louisiana. Although plaintiffs' claims against the other defendants have been pending since October 2012, plaintiffs are now alleging that EnLink Processing Services, LLC's negligence also contributed to the formation of the sinkhole. The amount of damages is unspecified. The validity of the causes of action, as well as our costs and legal exposure, if any, related to the lawsuit are not currently determinable. We intend to vigorously defend the case. We have also filed a claim for defense and indemnity with its insurers.

(15) Segment Information

Identification of the majority of our operating segments is based principally upon geographic regions served. Our reportable segments consist of the following: natural gas gathering, processing, transmission and fractionation operations located in north Texas, south Texas and the Permian Basin in west Texas ("Texas"), the pipelines and processing plants located in Louisiana and NGL assets located in south Louisiana ("Louisiana"), natural gas gathering and processing operations located throughout Oklahoma ("Oklahoma") and crude rail, truck, pipeline and barge facilities in west Texas, south Texas, Louisiana and Ohio River Valley ("Crude and Condensate"). Operating activity for intersegment eliminations is shown in the Corporate segment. Our sales are derived from external domestic customers.

Corporate expenses include general partnership expenses associated with managing all reportable operating segments. Corporate assets consist primarily of cash, property and equipment, including software, for general corporate support, debt financing costs and unconsolidated affiliate investments in HEP, GCF and the Cedar Cove JV. We evaluate the performance of our operating segments based on operating revenues and segment profits.

ENLINK MIDSTREAM PARTNERS, LP
Notes to Consolidated Financial Statements (Continued)

Summarized financial information for our reportable segments is shown in the following tables (in millions):

	Texas	Louisiana	Oklahoma	Crude and Condensate	Corporate	Totals
Year Ended December 31, 2016:						
Product sales	$ 237.2	$ 1,632.5	$ 48.5	$ 1,090.7	$ —	$ 3,008.9
Product sales - related parties	287.6	57.8	120.4	1.5	(333.0)	134.3
Midstream services	104.2	215.4	82.2	65.4	—	467.2
Midstream services - related parties	439.3	95.8	185.9	18.9	(86.8)	653.1
Cost of sales	(483.4)	(1,729.0)	(184.9)	(1,038.0)	419.8	(3,015.5)
Operating expenses	(168.5)	(96.6)	(52.1)	(81.3)	—	(398.5)
Loss on derivative activity	—	—	—	—	(11.1)	(11.1)
Segment profit (loss)	$ 416.4	$ 175.9	$ 200.0	$ 57.2	$ (11.1)	$ 838.4
Depreciation and amortization	$ (196.9)	$ (114.8)	$ (140.6)	$ (42.4)	$ (9.2)	$ (503.9)
Impairments	$ (473.1)	$ —	$ —	$ (93.2)	$ —	$ (566.3)
Goodwill	$ 232.0	$ —	$ 190.3	$ —	$ —	$ 422.3
Capital expenditures	$ 217.9	$ 79.1	$ 295.7	$ 74.3	$ 9.1	$ 676.1
Year Ended December 31, 2015:						
Product sales	$ 320.0	$ 1,527.7	$ 5.0	$ 1,401.0	$ —	$ 3,253.7
Product sales - related parties	123.3	48.5	13.0	0.8	(66.2)	119.4
Midstream services	100.2	244.1	28.3	78.4	—	451.0
Midstream services - related parties	456.7	20.0	140.7	18.0	(16.8)	618.6
Cost of sales	(412.2)	(1,567.6)	(17.9)	(1,330.6)	83.0	(3,245.3)
Operating expenses	(181.8)	(105.9)	(30.3)	(101.9)	—	(419.9)
Gain on derivative activity	—	—	—	—	9.4	9.4
Segment profit	$ 406.2	$ 166.8	$ 138.8	$ 65.7	$ 9.4	$ 786.9
Depreciation and amortization	$ (169.7)	$ (109.1)	$ (49.8)	$ (51.5)	$ (7.2)	$ (387.3)
Impairments	$ (496.3)	$ (787.3)	(0.6)	$ (279.2)	—	$ (1,563.4)
Goodwill	$ 703.5	$ —	$ 190.3	$ 93.2	$ —	$ 987.0
Capital expenditures	$ 268.0	$ 59.2	$ 40.7	$ 187.5	$ 15.1	$ 570.5
Year Ended December 31, 2014:						
Product sales	$ 216.5	$ 1,612.7	$ 13.1	$ 317.0	$ —	$ 2,159.3
Product sales - related parties	348.8	65.7	154.9	0.5	(64.3)	505.6
Midstream services	56.3	153.2	1.7	42.2	—	253.4
Midstream services - related parties	410.8	5.8	149.1	7.5	(5.8)	567.4
Cost of sales	(456.9)	(1,674.2)	(142.6)	(290.9)	70.1	(2,494.5)
Operating expenses	(146.8)	(64.9)	(28.7)	(43.2)	—	(283.6)
Gain on litigation settlement	—	6.1	—	—	—	6.1
Gain on derivative activity	—	—	—	—	22.1	22.1
Segment profit	$ 428.7	$ 104.4	$ 147.5	$ 33.1	$ 22.1	$ 735.8
Depreciation and amortization	$ (125.8)	$ (69.4)	$ (49.4)	$ (37.0)	$ (2.7)	$ (284.3)
Goodwill	$ 1,168.2	$ 786.8	$ 190.3	$ 112.5	$ —	$ 2,257.8
Capital expenditures	$ 271.0	$ 273.1	$ 17.1	$ 183.6	$ 13.9	$ 758.7

ENLINK MIDSTREAM PARTNERS, LP
Notes to Consolidated Financial Statements (Continued)

The table below represents information about segment assets as of December 31, 2016 and 2015 (in millions):

	Year Ended December 31,	
Segment Identifiable Assets:	**2016**	**2015**
Texas	$ 3,142.6	$ 3,709.5
Louisiana	2,349.3	2,309.3
Oklahoma	2,524.5	873.4
Crude and Condensate	836.8	898.0
Corporate	300.2	302.6
Total identifiable assets	$ 9,153.4	$ 8,092.8

The following table reconciles the segment profits reported above to the operating income (loss) as reported in the consolidated statements of operations (in millions):

	Year Ended December 31,		
	2016	**2015**	**2014**
Segment profits	$ 838.4	$ 786.9	$ 735.8
General and administrative expenses	(119.3)	(132.4)	(94.5)
Depreciation and amortization	(503.9)	(387.3)	(284.3)
Gain (loss) on disposition of assets	(13.2)	(1.2)	0.1
Impairments	(566.3)	(1,563.4)	—
Operating income (loss)	$ (364.3)	$ (1,297.4)	$ 357.1

(16) Quarterly Financial Data (Unaudited)

Summarized unaudited quarterly financial data is presented below (in millions, except per unit data):

	First	Second	Third	Fourth	Total
2016:					
Revenues	$ 889.7	$ 1,033.2	$ 1,104.6	$ 1,224.9	$ 4,252.4
Impairments	$ 566.3	$ —	$ —	$ —	$ 566.3
Operating income (loss)	$ (515.9)	$ 46.4	$ 66.9	$ 38.3	$ (364.3)
Net income (loss) attributable to EnLink Midstream Partners, LP	$ (560.4)	$ 5.0	$ 18.8	$ (28.6)	$ (565.2)
General partner interest in net income	$ 7.4	$ 10.6	$ 10.8	$ 10.7	$ 39.5
Limited partners' interest in net loss attributable to EnLink Midstream Partners, LP	$ (567.2)	$ (23.5)	$ (11.4)	$ (60.0)	$ (662.1)
Loss per limited partner unit - basic	$ (1.74)	$ (0.07)	$ (0.03)	$ (0.18)	$ (1.99)
Loss per limited partner unit - diluted	$ (1.74)	$ (0.07)	$ (0.03)	$ (0.18)	$ (1.99)
2015:					
Revenues	$ 940.5	$ 1,274.5	$ 1,170.6	$ 1,066.5	$ 4,452.1
Impairments	$ —	$ —	$ 799.2	$ 764.2	$ 1,563.4
Operating income (loss)	$ 51.5	$ 72.5	$ (730.5)	$ (690.9)	$ (1,297.4)
Net income (loss) attributable to EnLink Midstream Partners, LP	$ 35.6	$ 55.5	$ (754.9)	$ (714.0)	$ (1,377.8)
General partner interest in net income	$ 26.5	$ 19.1	$ 6.3	$ 6.1	$ 58.0
Limited partners' interest in net income (loss) attributable to EnLink Midstream Partners, LP	$ 9.0	$ 35.7	$ (745.2)	$ (704.7)	$ (1,405.2)
Income (loss) per limited partner unit - basic	$ 0.03	$ 0.12	$ (2.32)	$ (2.17)	$ (4.66)
Income (loss) per limited partner unit - diluted	$ 0.03	$ 0.12	$ (2.32)	$ (2.17)	$ (4.66)

ENLINK MIDSTREAM PARTNERS, LP
Notes to Consolidated Financial Statements (Continued)

(17) Discontinued Operations

The Predecessor's historical assets comprised all of Devon's U.S. midstream assets and operations. However, only our assets serving the Barnett, Cana-Woodford and Arkoma-Woodford Shales, as well as contractual rights to the benefits and burdens associated with Devon's 38.75% interest in GCF, were contributed to Midstream Holdings in connection with the Business Combination on March 7, 2014. All operations activity related to the non-contributed assets prior to March 7, 2014 are classified as discontinued operations.

The following schedule summarizes net income from discontinued operations (in millions):

	Year Ended December 31, 2014
Revenues:	
Revenues	$ 6.8
Revenues - related parties	10.5
Total revenues	17.3
Operating costs and expenses:	
Operating costs and expenses	15.7
Total operating costs and expenses	15.7
Income before income taxes	1.6
Income tax provision	(0.6)
Net income	$ 1.0

(18) Supplemental Cash Flow Information

The following schedule summarizes non-cash financing activities for the period presented (in millions):

	Year Ended December 31, 2016	Year Ended December 31, 2015
Non-cash financing activities:		
Installment payable, net of discount of $79.1 million (1)	$ 420.9	$ —
Non-cash issuance of common units (2)	—	180.0
Non-cash issuance of Class C Common Units (2)	—	180.0
Contribution from ENLC (3)	237.1	—
Non-cash adjustment of interest in Midstream Holdings (4)	—	66.5

(1) We incurred installment purchase obligations, net of discount, assuming payments of $250.0 million are made on January 7, 2017 and 2018, payable to the seller in connection with the acquisition of the EnLink Oklahoma T.O. assets. See "Note 3—Acquisitions" for further discussion.
(2) Non-cash common units and Class C Common Units were issued as partial consideration for the Coronado acquisition. See "Note 3—Acquisitions" for further discussion.
(3) Contribution from ENLC in connection with the acquisition of the EnLink Oklahoma T.O assets. See "Note 3—Acquisitions" for further discussion.
(4) Non-cash adjustment to reflect recast of Midstream Holdings' interests acquired on February 17, 2015 and May 27, 2015. See "Note 3—Acquisitions" for further discussion.

ENLINK MIDSTREAM PARTNERS, LP
Notes to Consolidated Financial Statements (Continued)

(19) Other Information

The following table presents additional detail for certain balance sheet captions.

Other Current Liabilities

Other current liabilities consisted of the following (in millions):

	Year Ended December 31,	
	2016	2015
Accrued interest	$ 34.2	$ 23.2
Accrued wages and benefits, including taxes	19.0	27.7
Accrued ad valorem taxes	23.5	27.0
Capital expenditure accruals	64.6	22.3
Onerous performance obligations	15.9	17.0
Other	59.8	57.2
Other current liabilities	$ 217.0	$ 174.4

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

None.

Item 9A. Controls and Procedures

(a) Evaluation of Disclosure Controls and Procedures

We carried out an evaluation, under the supervision and with the participation of management, including the Chief Executive Officer and Chief Financial Officer of EnLink Midstream GP, LLC, of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report pursuant to Exchange Act Rules 13a-15 and 15d-15. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that, as of the end of the period covered by this report (December 31, 2016), our disclosure controls and procedures were effective to provide reasonable assurance that information required to be disclosed by us in the reports we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported, within the time period specified in the applicable rules and forms, and that such information is accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, to allow timely decisions regarding disclosure.

(b) Changes in Internal Control Over Financial Reporting

There has been no change in our internal control over financial reporting that occurred in the three months ended December 31, 2016 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Internal Control Over Financial Reporting

See “Item 8. Financial Statements and Supplementary Data—Management’s Report on Internal Control over Financial Reporting.”

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

We are managed by the board of directors and executive officers of EnLink Midstream GP, LLC, our general partner. Our general partner is not elected by our unitholders and will not be subject to re-election by our unitholders in the future. Our general partner has a board of directors, and our common unitholders are not entitled to elect the directors or to participate directly or indirectly in our management or operations. Our operational personnel are employees of the Operating Partnership. References to our officers, directors and employees are references to the officers, directors and employees of our general partner or the Operating Partnership.

Our general partner will be liable, as general partner, for all of our debts (to the extent not paid from our assets), except for indebtedness or other obligations that are made specifically nonrecourse to it. Whenever possible, we intend to incur indebtedness that is nonrecourse to our general partner.

The following table shows information for the members of the board of directors (the "Board") and the executive officers of our general partner. Executive officers and directors serve until their successors are duly appointed or elected.

Name	Age	Position with EnLink Midstream GP, LLC
Barry E. Davis	55	Chief Executive Officer and Chairman of the Board
Michael J. Garberding	48	President and Chief Financial Officer
Steve J. Hoppe	54	Executive Vice President and President of Gas Gathering, Processing and Transmission
McMillan (Mac) Hummel	54	Executive Vice President and President of Natural Gas Liquids and Crude
Benjamin D. Lamb	37	Executive Vice President, Corporate Development
Alaina Brooks	42	Senior Vice President, General Counsel and Secretary
David A. Hager	60	Director and Member of the Compensation Committee
Mary P. Ricciardello (2)	61	Director and Member of the Audit Committee
Scott A. Griffiths (2)	62	Director and Member of the Compensation (1) and Conflicts Committees
Leldon E. Echols (2)	61	Director and Member of the Audit Committee (1)
Kyle D. Vann (2)	69	Director and Member of the Conflicts (1) and Audit Committees
Thomas Mitchell	56	Director
Tony Vaughn	59	Director
Christopher Ortega	41	Director
Sue Alberti	59	Director
Lyndon Taylor	57	Director

(1) Chairman of committee.
(2) Independent director.

Barry E. Davis, Chief Executive Officer and Chairman of the Board, led the management buyout of the midstream assets of Comstock Natural Gas, Inc. in December 1996, which transaction resulted in the formation of our predecessor. Mr. Davis has served as director since our initial public offering in December 2002. Mr. Davis was President and Chief Operating Officer of Comstock Natural Gas and founder of Ventana Natural Gas, a gas marketing and pipeline company that was purchased by Comstock Natural Gas. Mr. Davis started Ventana Natural Gas in June 1992. Prior to starting Ventana, he was Vice President of Marketing and Project Development for Endevco, Inc. Before joining Endevco, Mr. Davis was employed by Enserch Exploration in the marketing group. Mr. Davis holds a B.B.A. in Finance from Texas Christian University. Mr. Davis also serves as a director for EnLink Midstream, LLC. Mr. Davis's leadership skills and experience in the midstream natural gas industry, among other factors, led the Board to conclude that he should serve as Chairman of the Board.

Michael J. Garberding, President and Chief Financial Officer, joined our general partner in February 2008. Mr. Garberding assumed his current role in September 2016, having previously served as Senior Vice President and Chief Financial Officer, and Executive Vice President and Chief Financial Officer. Mr. Garberding previously led the finance and business development organization for the Partnership. Mr. Garberding has more than 25 years of experience in finance and accounting. From 2002 to 2008, Mr. Garberding held various finance and business development positions at TXU Corporation, including assistant treasurer. In addition, Mr. Garberding worked at Enron North America as a

Finance Manager and Arthur Andersen LLP as an Audit Manager. He received his Masters in Business Administration from the University of Michigan in 1999 and his B.B.A. in Accounting from Texas A&M University in 1991.

Steve J. Hoppe, Executive Vice President and President of Gas Gathering, Processing and Transmission, joined our general partner in March 2014. Previously, Mr. Hoppe served as Senior Vice President of Midstream Operations for Devon, which he joined in 2007. Mr. Hoppe has more than 25 years of midstream energy-industry experience, including eight years at Thunder Creek Gas Services, where he most recently served as President. Mr. Hoppe holds a Bachelor of Science degree in civil engineering from the University of Wyoming.

McMillan (Mac) Hummel, Executive Vice President and President of Natural Gas Liquids and Crude, joined the Managing Member and the General Partner in March 2014. Previously, Mr. Hummel served in various positions with The Williams Companies, which he joined in 1985, including Vice President of Commodity Services, Vice President of Natural Gas Liquids and Petchem Services and Vice President of Western Region Gathering and Processing. Mr. Hummel began his career with Williams' Northwest Pipeline while living in Salt Lake City, Utah. Mr. Hummel also served as Director of Business Development for Williams while living in Calgary, Alberta. Mr. Hummel has been a member of the American Fuel & Petrochemical Manufacturers Petrochemical Committee, the Association of Oil Pipe Lines Pipeline Subcommittee and the board of Aux Sable Liquids Partners. Mr. Hummel earned a Bachelor of Science degree in accounting and a Masters of Business Administration from the University of Utah.

Benjamin D. Lamb, Executive Vice President, Corporate Development, joined our general partner in December 2012. Mr. Lamb assumed his current role in September 2016, having previously served as Vice President – Finance, and Senior Vice President, Finance and Corporate Development. Prior to joining our general partner, Mr. Lamb served as a Principal at the investment banking firm Greenhill & Co., which he joined in 2005. In that role he focused on the evaluation and execution of mergers, acquisitions and restructuring transactions for clients primarily in the midstream energy, power and utility industries. Prior to joining Greenhill he served as an investment banker at UBS Investment Bank in its Mergers and Acquisitions Group and in its Global Energy Group, and at Merrill Lynch in its Global Energy and Power Group. Mr. Lamb received his Bachelor of Business Administration degree from Baylor University in 2000.

Alaina K. Brooks, Senior Vice President, General Counsel and Secretary, joined our general partner in 2008. Ms. Brooks has served in several legal roles within EnLink Midstream, most recently as Deputy General Counsel before assuming the role of Senior Vice President, General Counsel and Secretary in September 2014. In Ms. Brooks' current role, she serves on EnLink Midstream's Senior Leadership Team and leads the legal and regulatory functions. Before joining our general partner in 2008, Ms. Brooks practiced law at Weil, Gotshal & Manges LLP and Baker Botts LLP, where she counseled clients on matters of complex commercial litigation, risk management and taxation. Ms. Brooks is a licensed Certified Public Accountant and holds a Juris Doctor degree from Duke University School of Law and Bachelor of Science and Master of Science degrees in accounting from Oklahoma State University.

David A. Hager has served as the President and Chief Executive officer of Devon since August 1, 2015. Prior to that, Mr. Hager served as Chief Operating Officer of Devon since June 2013. He joined Devon in 2009 as Executive Vice President of Exploration and Production. Prior to Devon, Mr. Hager held several positions within Kerr-McGee Corp, most recently as Chief Operating Officer in the period just before its merger with Anadarko Petroleum. Mr. Hager was a Director and Chairman of the Reserves Committee on Devon's Board from 2007 until 2009 and has served as a director for Pride International, Inc. Mr. Hager has served as a director of our general partner and the managing member of EnLink Midstream since completion of the Business Combination on March 7, 2014. He holds a Bachelor of Science degree in Geophysics from Purdue University and a Master's in Business Administration degree from Southern Methodist University. Mr. Hager was selected to serve as a director due to his affiliation with Devon, his knowledge of the energy business and his business expertise.

Mary P. Ricciardello was Senior Vice President and Chief Accounting Officer at Reliant Energy Inc., a leading independent power producer and marketer until 2002. She began her career with Reliant in 1982 and served in various financial management positions with the company including Comptroller, Senior Vice President and Chief Accounting Officer. Ms. Ricciardello has served as a director of our general partner and the managing member of EnLink Midstream since March 2014. Ms. Ricciardello also serves as a director on the boards of Devon and Noble Corporation and has served as a director on the Board of Midstates until March 2015. Ms. Ricciardello is also a NACD Board Leadership Fellow. Ms. Ricciardello holds a Bachelor of Science degree in Business Administration from the University of South Dakota and a Master's in Business Administration with an emphasis in Finance from the University of Houston. She is a licensed Certified Public Accountant. Ms. Ricciardello was selected to serve as a director due to her qualifications as a financial expert and her extensive experience in the energy industry, as well as corporate finance and tax matters.

Scott A. Griffiths has been an independent Oil and Gas Consultant since 2007, advising clients on various Gulf of Mexico investment opportunities. Prior to that, he served as Senior Vice President and Chief Operating Officer of Hydro Gulf of Mexico, LLC until December 2006. Mr. Griffiths was Executive Vice President and Chief Operating Officer of Spinnaker Exploration Company and also served in senior management and exploration roles at Ocean Energy, Inc., Global Natural Resources, Inc. and Shell Oil Company. Mr. Griffiths has served as a director of our general partner since completion of the Business Combination on March 7, 2014. Mr. Griffiths served as a director on the Board of Copano Energy, LLC until it was acquired by Kinder Morgan Energy Partners in 2013 and also served as a director on the Board of Energy XXI Ltd. until December 30, 2016. He holds a Bachelor of Science in Geology from the University of New Mexico, a Master's in Geology from Indiana University and completed the Advanced Management Program at Harvard Business School. Mr. Griffiths was selected to serve a director due to his extensive experience in the energy industry, his knowledge of oil and gas exploration and his business expertise.

Leldon E. Echols joined Crosstex Energy, Inc. as a director in January 2008. Mr. Echols is a private investor. Mr. Echols also currently serves as an independent director of the managing member of EnLink Midstream, Trinity Industries, Inc. and HollyFrontier Corporation, an independent petroleum refiner and marketer. Mr. Echols brings 30 years of financial and business experience to the General Partner. After 22 years with the accounting firm Arthur Andersen LLP, which included serving as managing partner of the firm's audit and business advisory practice in North Texas, Colorado and Oklahoma, Mr. Echols spent six years with Centex Corporation as executive vice president and chief financial officer. He retired from Centex Corporation in June 2006. Mr. Echols previously served as a member of the board of directors of Roofing Supply Group Holdings, Inc., a private company. He also served on the board of TXU Corporation where he chaired the Audit Committee and was a member of the Strategic Transactions Committee until the completion of the private equity buyout of TXU in October 2007. Mr. Echols earned a Bachelor of Science degree in accounting from Arkansas State University and is a licensed Certified Public Accountant. He is a member of the American Institute of Certified Public Accountants and the Texas Society of CPAs. Mr. Echols also served as a director of the Crosstex Energy Inc. from January 2008 until the Mergers. Mr. Echols was selected to serve as a director due to his accounting and financial experience and service as the chief financial officer for another public company, among other factors.

Kyle D. Vann joined our general partner as a director in April 2006. Mr. Vann began his career with Exxon Corporation in 1969. After ten years at Exxon, he joined Koch Industries and served in various leadership capacities, including senior vice president from 1995-2000. In 2001, he then took on the role of CEO of Entergy-Koch, LP, an energy trading and transportation company, which was sold in 2004. Currently, Mr. Vann continues to consult with Entergy and is an executive advisor to CCMP Capital Advisors, LLC. He also serves on the boards of Texon, L.P., PQ Chemical and Legacy Reserves, LLC (NASDAQ: LGCY). He also serves as a director on the Boards of Mars Hill Productions and Generous Giving, which are private, charitable non-profits. Mr. Vann graduated from the University of Kansas with a Bachelor of Science degree in chemical engineering. He is a member of the Board of Advisors for the University of Kansas School of Engineering (where he was a recipient of the Distinguished Engineering Service Award). Mr. Vann was selected to serve as a director due to his extensive experience in the energy industry and his business expertise, among other factors.

Thomas L. Mitchell has over 30 years of experience in the oil and gas industry and joined Devon as Executive Vice President and Chief Financial Officer in February 2014. Prior to Devon, Mr. Mitchell served on the board of directors and as the Executive Vice President and Chief Financial Officer of Midstates Petroleum Company throughout its initial public offering process. Prior to that, Mr. Mitchell served as Senior Vice President and Chief Financial Officer of Noble Corporation and spent 18 years with Apache Corporation in various financial and commercial roles. Mr. Mitchell has served as a director of our general partner and the managing member of EnLink Midstream since completion of the Business Combination on March 7, 2014. He also is a director on the Board of Hines Global REIT, Inc., a public real estate investment trust managed by Hines Interests, and holds a Bachelor of Science degree in Accounting from Bob Jones University. Mr. Mitchell was selected to serve as a director due to his affiliation with Devon, his knowledge of the energy business and his financial and business expertise.

Tony Vaughn joined our general partner as a director in January 2016. Mr. Vaughnis employed by Devon Energy Corporation ("Devon"), and he was elected to the position of Executive Vice President of Exploration and Production of

Devon in 2013. From 1999 until 2013, Mr. Vaughn served in various positions at Devon, including most recentlyas Senior Vice President of Exploration and Production and Strategic Services. Before joining Devon in 1999, Mr. Vaughn spent 12 years with Kerr-McGee Corporation, most recently as Manager of the Rocky Mountain District. He holds a Bachelor of Science degree in Petroleum Engineering from the University of Tulsa and Bachelor of Science Degree in Business Management from Oral Roberts University. He is a member of the Society of Petroleum Engineers. Mr. Vaughn was selected to serve as a director due to his affiliation with Devon, his knowledge of the energy business and his business expertise.

Christopher Ortega joined our general partner as a director in January 2016. Mr. Ortega is a Partner of TPG. He has over 10 years of experience in the energy sector and currently sits on the board of Jonah Energy and is a director of the general partner of Axip Energy Services, LP (formerly known as Valerus Compression Services, LP). Mr. Ortega has previously served on the boards of AMCI Capital, Barra Energia, Connect Resource Services, DOF Subsea, and LMP Exploration. Mr. Ortega's responsibilities encompass investment origination, structuring, execution, monitoring, and exit strategy. He has a particular focus on the upstream oil & gas, oilfield services, and midstream sectors. Prior to TPG Capital, Mr. Ortega was a director at First Reserve Corporation. He graduated magna cum laude from Harvard Law School and received an MBA from Harvard Business School. Mr. Ortega received his AB, magna cum laude, from Harvard University. Mr. Ortega was selected as a director pursuant to a Board Representation Agreement entered into on January 7, 2016 between us, our general partner, EMI and TPG VII Management, LLC, an affiliate of Enfield Holdings, L.P., the purchaser in the private placement consummated on January 7, 2016. Mr. Ortega brings to the Board investment, financial and industry experience.

Sue Alberti, has been Senior Vice President of Marketing, Supply Chain and Strategic Planning for Devon since September 2016. She previously served as Vice President Compensation and Benefits. Ms. Alberti has been with Devon since 2008. Prior to joining Devon, Ms. Alberti worked at Texas Instruments for seven years, most recently serving as Vice President of worldwide compensation, benefits and human resources mergers and acquisitions. Ms. Alberti holds a bachelor's degree in chemical engineering from the University of Michigan and a master's in business administration and finance from the University of Chicago.

Lyndon Taylor was elected to the position of Executive Vice President and general counsel of Devon in February 2007. Mr. Taylor had served as Devon's deputy general counsel since August 2005. Prior to joining Devon, Mr. Taylor was with Skadden, Arps, Slate, Meagher & Flom, LLP for 20 years and served as managing partner of the firm's Houston office from 1993 to 2005. He is admitted to practice law in Oklahoma and Texas. Mr. Taylor received his Bachelor of Science degree in industrial engineering from Oklahoma State University and his law degree from the University of Oklahoma.

Independent Directors

Because we are a limited partnership, the NYSE does not require the Board to be composed of a majority of directors who meet the criteria for independence required by the NYSE or to maintain nominating/corporate governance and compensation committees composed entirely of independent directors. Our Board has adopted Governance Guidelines that require at least three members of our Board to be independent directors as defined by the rules of the NYSE.

For a director to be "independent" under the NYSE standards, the Board must affirmatively determine that the director has no material relationship with the Partnership (either directly or as a partner, shareholder or officer of any organization that has a relationship with the Partnership, other than in his or her capacity as a director of the Partnership). In addition, the director must meet certain independence standards specified by the NYSE, including a requirement that the director was not employed by our general partner or engaged in certain business dealings with our general partner. Using these standards for determining independence, the Board has determined that Messrs. Echols, Vann, Griffiths and Ms. Ricciardello qualify as "independent" directors.

In addition, the members of the Audit Committee of our Board each qualify as "independent" under special standards established by the Securities and Exchange Commission ("SEC") for members of audit committees, and the Audit Committee includes at least one member who is determined by our Board to meet the qualifications of an "audit committee financial expert" in accordance with SEC rules, including that the person meets the relevant definition of an "independent" director. Mr. Echols and Ms. Ricciardello are both independent directors who have been determined to be audit committee financial experts. Unitholders should understand that this designation is a disclosure requirement of the SEC related to their experience and understanding with respect to certain accounting and auditing matters. The designation does not impose on such directors any duties, obligations or liabilities that are greater than are generally imposed on them as members of the Audit Committee and the Board, and the designation of a director as audit committee financial experts pursuant to this SEC requirement does not affect the duties, obligations or liabilities of any other member of the Audit Committee or the Board. Additionally, the Board has determined that the simultaneous service by Mr. Echols and Ms. Ricciardello on the Audit Committees of three other publicly traded companies on which they serve does not impair their ability to effectively serve on the Audit Committee of our general partner.

Board Committees

The Board has, and appoints the members of, standing Audit, Conflicts and Compensation Committees. Each member of the Audit, Compensation and Conflicts Committees is an independent director in accordance with NYSE standards described above. Each of the board committees has a written charter approved by the Board. Copies of the charters and our Code of Business Conduct and Ethics are available to any person, free of charge, at our web site: www.enlink.com.

The Audit Committee, comprised of Messrs. Echols (chair), Vann and Ms. Ricciardello, assists the Board in its general oversight of our financial reporting, internal controls and audit functions, and is directly responsible for the appointment, retention, compensation and oversight of the work of our independent auditors.

The Conflicts Committee, comprised of Messrs. Vann (chair) and Griffiths, reviews specific matters that the Board believes may involve conflicts of interest. The Conflicts Committee determines if the resolution of a conflict of interest is fair and reasonable to us. The members of the Conflicts Committee are not directors, officers or employees of EnLink Midstream, LLC, the owner of our general partner. Any matters approved by the Conflicts Committee will be conclusively deemed to be fair and reasonable to us, approved by all of our partners and not a breach by our general partner of any duties owed to us or our unitholders.

The Compensation Committee, comprised of Messrs. Griffiths (chair) and Hager, oversees compensation decisions for the officers of our general partner as well as the compensation plans described herein.

Board Meetings and Attendance

Our Board met seven times in 2016. All incumbent directors attended in excess of 95% of the total number of meetings of our Board and committees of our Board on which they served.

The non-management directors meet in executive session without management participation at least quarterly. Unitholders or interested parties may communicate with non-management directors by sending written communications to the following address, to the attention of the Chairman of the Board, who presides at the executive sessions of the non-management directors of the Board: EnLink Midstream Partners, LP, 2501 Cedar Springs Rd., Suite 100, Dallas, Texas 75201.

Code of Ethics and Governance Guidelines

Our general partner has adopted a Code of Business Conduct and Ethics (the "Code of Ethics") applicable to all of our employees, officers and directors with regard to Partnership-related activities. The Code of Ethics incorporates guidelines designed to deter wrongdoing and to promote honest and ethical conduct and compliance with applicable laws and regulations. It also incorporates expectations of our employees that enable us to provide accurate and timely disclosure in our filings with the SEC and other public communications. Our general partner has also adopted Governance Guidelines that outline the important policies and practices regarding our governance and provide an effective framework for the functioning of our Board and its committees. A copy of the Code of Ethics and the Governance Guidelines are available to any person, free of charge, within the "Governance Documents" subsection of the "Corporate Governance" section of the investors section of our website at www.enlink.com. If any substantive amendments are made to the Code of Ethics or if we or our general partner grants any waiver, including any implicit waiver, from a provision of the Code of Ethics to any of our general partner's executive officers and directors, we will disclose the nature of such amendment or waiver on our website. The information contained on, or connected to, our website is not incorporated by reference into this annual report on Form 10-K and should not be considered part of this or any other report that we file with or furnish to the SEC.

Section 16(a)—Beneficial Ownership Reporting Compliance

Section 16(a) of the Securities Exchange Act of 1934 requires our directors, executive officers and 10% unitholders to file with the SEC reports of ownership and changes in ownership of our equity securities. Based solely upon a review of the copies of the Forms 3, 4 and 5 reports furnished to us and written representations from our directors and executive officers, except as set forth below, we believe that during 2016, all of our directors, executive officers and beneficial owners of more than 10% of our common units complied with Section 16(a) filing requirements applicable to them, other than a Form 3 for Susan Alberti, which was filed one day late due to administrative issues on July 6, 2016.

Reimbursement of Expenses of our General Partner and its Affiliates

Our general partner does not receive any management fee or other compensation in connection with its management of our partnership. However, our general partner performs services for us and is reimbursed by us for all expenses incurred on our behalf, including the costs of employee, officer and director compensation and benefits, as well as all other expenses necessary or appropriate to the conduct of our business. The partnership agreement provides that our general partner will determine the expenses that are allocable to us in any reasonable manner determined by our general partner in its sole discretion.

Item 11. Executive Compensation

Compensation Committee Report

Each member of the Compensation Committee is an independent director in accordance with NYSE standards. The Compensation Committee has reviewed and discussed with management the following section titled "Compensation Discussion and Analysis." Based upon its review and discussions, the Compensation Committee has recommended to the Board that the Compensation Discussion and Analysis be included in this Annual Report on Form 10-K.

By the Members of the Compensation Committee:

Scott A. Griffiths (Chairman)

David A. Hager

Compensation Discussion and Analysis

The following Compensation Discussion and Analysis contains statements regarding our compensation programs and our executive officers' business priorities related to our compensation programs and target payouts under the programs. These business priorities are disclosed in the limited context of our compensation programs and should not be understood to be statements of management's expectations or estimates of results or other guidance.

Overview

We do not directly employ any of the persons responsible for managing our business. EnLink Midstream GP, LLC, our general partner, manages our operations and activities, and its Board and officers make decisions on our behalf. The compensation of the executive officers of EnLink Midstream GP, LLC is determined by the Board upon the recommendation of its Compensation Committee. The compensation of the directors of EnLink Midstream GP, LLC is determined by the Board upon the recommendation of its Governance Committee. Our named executive officers also serve as named executive officers of EnLink Midstream, LLC and the compensation of the named executive officers discussed below reflects total compensation for services to all EnLink entities. We pay or reimburse all expenses incurred on our behalf, including the costs of employee, officer and director compensation and benefits, as well as all other expenses necessary or appropriate to the conduct of our business. Our partnership agreement provides that our general partner will determine the expenses allocable to us in any reasonable manner determined by our general partner in its sole discretion. EnLink Midstream, LLC currently pays a monthly fee to EnLink Midstream GP, LLC to cover its portion of administrative and compensation costs, including compensation costs relating to the named executive officers.

Based on the information that we track regarding the amount of time spent by each of our named executive officers on business matters relating to EnLink Midstream Partners, LP, we estimate that such officers devoted the following percentage of their time to the business of EnLink Midstream Partners, LP and to EnLink Midstream, LLC, respectively, for 2016

Executive Officer or Director	Percentage of Time Devoted to Business of EnLink Midstream Partners, LP	Percentage of Time Devoted to Business of EnLink Midstream, LLC
Barry E. Davis	80%	20%
Michael J. Garberding	60%	40%
Steve J. Hoppe	90%	10%
Mac Hummel	90%	10%
Benjamin D. Lamb	90%	10%

Compensation Philosophy and Principles

Our executive compensation is designed to attract, retain and motivate top-tier executives and align their individual interests with the interests of our unitholders. It is the Compensation Committee's responsibility to design and administer compensation programs that achieve these goals, and to make recommendations to the Board to approve and adopt these programs. The compensation of each of our executives is primarily comprised of base salary, bonus opportunity and equity-based awards under our long-term incentive plans. The Compensation Committee's philosophy is to generally target the 50th percentile of our Peer Group (discussed below) for base salaries and bonuses (but retain discretion to reduce or increase bonus amounts to address individual performance) and to provide executives the opportunity to earn long-term incentive compensation, in the form of equity, targeted at the 75th percentile of our Peer Group.

The Compensation Committee considers the following principles in determining the total compensation of the named executive officers:

- the total compensation program, including base salary and bonus opportunities, should be competitive with the market in which we compete for executive talent in order to attract, retain and motivate highly qualified executive officers;

- equity-based incentive compensation should represent a significant portion of the executive's total compensation in order to retain and incentivize highly qualified executives and align their individual long-term interests with the interests of unitholders;

- compensation programs should be sufficiently flexible to address special circumstances, which include payments under retention plans specifically targeted to retain highly qualified executives during challenging times; and

- the overall compensation program should drive performance and reward contributions in support of our business strategies and achievements.

Compensation Methodology

Annually, the Compensation Committee reviews our executive compensation program in total and each element of compensation specifically. The review includes an analysis of the compensation practices of other companies in our industry, the competitive market for executive talent, the evolving demands of the business, specific challenges that we may face and individual contributions to us and our general partner. The Compensation Committee recommends to the Board adjustments to the overall compensation program and to its individual components as the Compensation

Committee determines necessary to achieve our goals. The Compensation Committee periodically retains consultants to assist in its review and to provide input regarding the compensation program and each of its elements.

Role of Compensation Consultant

The Compensation Committee has retained Meridian Compensation Partners, LLC ("Meridian") as its independent compensation consultant to conduct a compensation review and advise the Compensation Committee on certain matters relating to compensation programs applicable to the named executive officers and other employees of our general partner. In particular, Meridian has assisted the Compensation Committee's decision making with respect to executive officer and director compensation matters, including providing advice on our executive pay philosophy, compensation peer group, incentive plan design and employment agreement design, providing competitive market studies, and apprising the Compensation Committee about emerging best practices and changes in the regulatory and governance environment. Meridian provided information to the Compensation Committee regarding the compensation programs of the EnLink entities for 2016. Meridian's work for the Compensation Committee did not raise any conflicts of interest in 2016.

Role of Peer Group and Benchmarking

For 2016, the Compensation Committee and Meridian collaborated to identify the following companies as our peer companies: Boardwalk Partners, L.P., Buckeye Partners, L.P., Enable Midstream Partners, LP, Enbridge Energy Partners, L.P., Genesis Energy, L.P., HollyFrontier Corp., Magellan Midstream Partners, L.P., ONEOK Partners, L.P., Pembina Pipeline Corp., Plains All American Pipeline, L.P., Spectra Energy Corp., Sunoco Logistics Partners, L.P., Targa Resource Partners, L.P. and Western Gas Partners, L.P. (the "Peer Group"). We believe that this group of companies is representative of the industry in which we operate. The individual companies were chosen based on a number of factors, including each company's, relative size/market capitalization, relative complexity of its business, similar organizational structure, competition for similar executive talent and the roles and responsibilities of its named executive officers. The Compensation Committee considers the Peer Group companies annually, but historically there have been few changes from year to year. Companies are typically added or removed from the Peer Group as the result of a change in organizational structure or relative size/market capitalization as compared to us.

When evaluating annual compensation levels for each named executive officer, the Compensation Committee, with the assistance of Meridian, reviews publicly available compensation data for executives in our Peer Group, including data on base salaries, annual cash bonuses, and long-term equity incentive awards, as well as compensation surveys. The Compensation Committee then uses that information to help set compensation levels and compensation program elements for the named executive officers in the context of their roles, levels of responsibility, accountability and decision-making authority within our organization and in the context of company size relative to the other Peer Group members. In addition, Meridian has provided guidance on current industry trends and best practices to the Compensation Committee relating to all aspects of executive compensation, bonus structure and bonus methodology.

While compensation data from the Peer Group is considered, the Compensation Committee does not attempt to set compensation components to meet specific benchmarks. The Peer Group data that is reviewed by the Compensation Committee is simply one factor out of many that is used in connection with the establishment of compensation opportunities for our named executive officers. The other factors considered include, but are not limited to, (i) available compensation data, rankings and comparisons, (ii) effort and accomplishment on a group and individual basis, (iii) challenges faced and challenges overcome, (iv) unique skills, (v) contribution to the management team, (vi) succession planning and retention of our executive officers and (vii) the perception of both the Board and the Compensation Committee of our performance relative to expectations and actual market/business conditions. All of these factors, including Peer Group data and analysis, are utilized in a subjective assessment of each year's decisions relating to base salary, annual cash bonus, and long-term equity incentive award decisions.

Elements of Compensation

For fiscal year 2016, the principal elements of compensation for the named executive officers were the following:

- base salary;
- annual bonus awards;

- long-term incentive plan awards;
- retirement and health benefits; and
- severance and change of control benefits.

The Compensation Committee reviews and makes recommendations regarding the mix of compensation, both among short- and long-term compensation and cash and non-cash compensation, to establish structures that it believes are appropriate for each of the named executive officers. We believe that the mix of base salary, annual bonus awards, awards under the long-term incentive plan, retirement and health benefits, severance and change of control benefits and perquisites and other compensation fit our overall compensation objectives. We believe this mix of compensation provides competitive compensation opportunities to align and drive employee performance in support of our business strategies and to attract, motivate and retain high quality talent with the skills and competencies that we require.

Base Salary. The Compensation Committee recommends base salaries for the named executive officers based on the historical salaries for services rendered to EnLink Midstream GP, LLC and its affiliates, market data provided by Meridian and from compensation surveys and responsibilities of the named executive officers. Base salaries are generally determined by considering the employee's performance and prevailing levels of compensation in areas in which a particular employee works. The base salaries paid to our named executive officers for fiscal year 2016 (and payable for fiscal 2017) are as follows:

	Prior Salary	Base Salary Effective For 2017 (1)	Percent Increase
Barry E. Davis	$ 660,000	$ 695,000	5.3 %
Michael J. Garberding	450,000	500,000	11.1 %
Steve J. Hoppe	390,000	420,000	7.7 %
Mac Hummel	390,000	420,000	7.7 %
Benjamin D. Lamb	310,000	345,000	11.3 %

(1) In association with a promotion effective September 22, 2016, Michael Garberding and Benjamin Lamb's base salaries were increased to $500,000 and $345,000, respectively. All other base salary increases were effective as of January 1, 2017.

Bonus Awards. All employees, including our named executive officers, are eligible to receive annual bonuses under the short-term incentive program (the "STI Program"). The Compensation Committee and the Board oversee the STI Program. Under the STI Program, bonuses are awarded to employees based on an approach that utilizes certain metrics to measure success and are subject to the discretion of the Compensation Committee and the Board. The named executive officers are designated as corporate officers, gas business unit officers or liquids business unit officers for purposes of the STI Program. The metrics employed by the STI Program vary depending on the applicable officer's business unit designation. The STI Program contemplates that (i) named executive officers designated as corporate officers will be eligible for bonuses based on our overall achievement level of EBITDA (see "Item 7 Management's Discussion and Analysis of Financial Condition and Results of Operations—Non-GAAP Measures" for definition) and certain safety metrics, (ii) named executive officers designated as gas business unit officers will be eligible for bonuses based on a weighted average of (x) our achievement of EBITDA and safety metrics and (y) our gas business unit's achievement of net operating income ("NOI") and safety metrics and (iii) named executive officers designated as liquids business unit officers will be eligible for bonuses based on a weighted average of (A) our achievement of EBITDA and safety metrics and (B) our liquids business unit's achievement of NOI and safety metrics. The Compensation Committee recommends and the Board sets annual weightings used in the foregoing bonus calculations applicable to gas business unit and liquids business unit officers.

In addition, the Compensation Committee and the Board, with input from management, will set annual EBITDA and NOI threshold, target and maximum goals based on a number of considerations, including reasonable market expectations, internal company forecasts, available investment opportunities and company performance. Such goals will vary from year to year. The Committee and the Board, with input from management, will also set annual safety index score threshold, target and maximum goals for each of corporate, gas business unit and liquids business unit. The safety goals will vary from year to year and will vary among each of corporate, gas business unit and liquids business unit. The safety index score is developed based on four categories: (i) safety statistics, including certain incident rates; (ii) leading indicators, such as safety meeting and training attendance; (iii) knowledge and development, which is based on standard assessments; and (iv) safety programs, including completed facility assessments and implementation of environmental, health and safety standards. Management of each of the gas business unit and the liquids business unit will participate in setting specific goals within the foregoing categories to ensure that the safety program influences and incents desired outcomes.

The Board, based on recommendations of the Compensation Committee, will determine final bonus amounts under the STI Program for the named executive officers. The Compensation Committee believes that a portion of executive compensation must remain discretionary and subject to the discretion of the Compensation Committee and the Board with respect to bonus awards payable to its named executive officers. Therefore, the STI Program contemplates that the Compensation Committee and the Board retain discretion with respect to bonus awards payable to named executive officers. The Compensation Committee may exercise its discretion to reduce or supplement the amount of the bonus for a particular named executive officer to reward or address extraordinary individual performance, challenges and opportunities not reasonably foreseeable at the beginning of a performance period, internal equities, and external competition or opportunities.

The final amount of bonus for each named executive officer was approved by the Board based upon the Compensation Committee's recommendation and assessment of whether such officer met his or her performance objectives established at the beginning of the performance period. These performance objectives included the quality of leadership within the named executive officer's assigned area of responsibility, the achievement of technical and professional proficiencies by the named executive officer, the execution of identified priority objectives by the named executive officer and the named executive officer's contribution to, and enhancement of, the desired company culture. These performance objectives were reviewed and evaluated by the Compensation Committee as a whole. All of our named executive officers met or exceeded their minimum personal performance objectives for 2016. Accordingly, the Compensation Committee and the Board awarded bonuses to the named executive officers as follows:

	Target Bonus Percentage (as a % of Base Salary)	2016 Bonus (as a % of Base Salary)	2016 Bonus Amount
Barry E. Davis	125 %	99 %	650,000
Michael J. Garberding	90 %	83 %	416,000
Steve J. Hoppe	90 %	72 %	280,000
Mac Hummel	90 %	58 %	225,000
Benjamin D. Lamb (1)	90 %	72 %	250,000

(1) In association with a promotion effective September 22, 2016, Benjamin Lamb's target bonus percentage increased from 60% to 90%.

Target adjusted EBITDA was based upon a standard of reasonable market expectations and company performance and varies from year to year. Several factors are reviewed in determining target adjusted EBITDA, including market expectations, internal forecasts and available investment opportunities. For 2016, our adjusted EBITDA levels for bonuses were \$770.0 million for minimum bonuses, \$806.0 million for target bonuses and \$844.0 million for maximum bonuses. For 2016, the STI Program provided for named executive officers to receive bonus payouts of 45% to 62.5% of base salary at the minimum threshold, 90% to 125% of base salary at the target level and 180% to 250% of base salary at the maximum level.

Long-Term Incentive Plans. We believe that equity awards are instrumental in attracting, retaining and motivating employees, and that they align the interests of our general partner's officers and directors with the interests of our unitholders. Accordingly, such directors and officers are eligible to participate in the EnLink Midstream GP, LLC Long-Term Incentive Plan (the "GP Plan"). In addition, our directors and officers are also eligible to participate in the EnLink Midstream, LLC 2014 Long-Term Incentive Plan (the "2014 Plan"). Finally, certain directors, officers and employees participate, to the extent consistent with terms and agreed in connection with the Business Combination, in the EnLink Midstream, LLC 2009 Long-Term Incentive Plan (the "2009 Plan").

The Board, at the recommendation of the Compensation Committee, approves the grants of awards to our named executive officers. The Compensation Committee believes that equity compensation should comprise a significant portion of a named executive officer's compensation and considers a number of factors when determining the grants to each individual. The factors considered include: the general goal of allowing the named executive officer the opportunity to earn aggregate equity compensation (comprised of our units and ENLC units) targeted at the 75th percentile of our Peer Group; the amount of unvested equity held by the individual named executive officer; the named executive officer's performance; and other factors as determined by the Compensation Committee.

A discussion of each plan follows:

EnLink Midstream GP, LLC Long-Term Incentive Plan. EnLink Midstream GP, LLC has adopted the "GP Plan" for employees, consultants and independent contractors of EnLink Midstream GP, LLC and its affiliates and outside directors of our Board who perform services for us. The GP Plan is administered by the Compensation Committee and permits the grant of awards, which may be awarded in the form of restricted incentive units or unit options. On May 9, 2013, our unitholders approved the amendment and restatement of the GP Plan, which increased the number of common units representing limited partner interests in the Partnership authorized for issuance under the GP Plan by 3,470,000 common units to an aggregate of 9,070,000 common units and made certain other technical amendments. Effective April 6, 2016, our unitholders approved the amendment and restatement of the GP Plan, which increased the number of common units representing limited partner interests in the Partnership authorized for issuance under the GP Plan by 5,000,000 common units to an aggregate of 14,070,000 common units and other technical changes. Of the 14,070,000 common units that may be awarded under the GP Plan, 6,012,007 common units remain eligible for future grants as of December 31, 2016. The long-term compensation structure of the GP Plan is intended to align the participant's performance with long-term performance for our unitholders.

The GP Plan will automatically expire on March 3, 2026. The Board, in its discretion, may terminate or amend the GP Plan at any time with respect to any units for which a grant has not yet been made. The Board or the Committee also has the right to alter or amend the GP Plan or any part of the GP Plan from time to time, including increasing the number of units that may be granted subject to the approval requirements of the exchange upon which the common units are listed at that time. The Compensation Committee may generally amend the terms of any outstanding award under the GP Plan at any time. However, no action may be taken by the Board or the Compensation Committee under the GP Plan that would materially reduce the benefits of a participant under a previously granted award without the consent of the participant.

The following forms of awards may be awarded under the GP Plan:

- *Unit Options.* The GP Plan currently permits the grant of options covering common units. These options are rights to purchase a specified number of common units of the Partnership at a specified price. All unit option grants will have an exercise price that is not less than 100% of the fair market value of the common units on the date of grant. In general, unit options granted will become exercisable over a period determined by the Compensation Committee and the term of the options cannot exceed ten years from the date of grant. Under no circumstances will distributions or DERs (as defined below) be granted or made with respect to option awards. In addition, the unit options may, pursuant to their terms, become exercisable upon a change of control of us, our general partner or EnLink Midstream as discussed below under "-Potential Payments Upon a Change of Control." Common units to be delivered upon the exercise of a unit option may be common units acquired by our general partner in the open market, common units already owned by our general partner, common units acquired by our general partner directly from us or any other person, or any combination of the foregoing. Our general partner will be entitled to reimbursement by us for the difference between the cost incurred by it in acquiring these common units and the proceeds received by it from an optionee at the time of exercise. Thus, the cost of the unit options will be borne by us. If we issue new common units upon exercise of the unit options our general partner will pay us the proceeds it received from the optionee upon exercise of the unit option.

- *Restricted Incentive Units.* The GP Plan currently permits the grant of restricted incentive units. These awards of restricted incentive units are rights that entitle the grantee to receive common units upon the vesting of such restricted incentive units. The Compensation Committee will determine the terms, conditions and limitations applicable to any awards of restricted incentive units. Awards of restricted incentive units will have a vesting period established in the sole discretion of the Compensation Committee, which may include, without limitation, vesting upon the achievement of specified performance goals. In addition, the restricted incentive units may, pursuant to their terms, vest upon a change of control of us, our general partner or EnLink Midstream, as discussed below under "-Potential Payments Upon a Change of Control." Common units to be delivered upon the vesting of restricted incentive units may be common units acquired by our general partner in the open market, common units already owned by our general partner, common units acquired by our general partner directly from us or any other person or any combination of the foregoing. Our general partner will be entitled to reimbursement by us for the cost incurred in acquiring common units. The Compensation Committee, in its discretion, may grant tandem distribution equivalent rights ("DERs") with respect to restricted incentive units, which entitles a participant to receive cash or additional awards equal to the amount of any cash distributions made by us with respect to a common unit during the period the DER is outstanding. The Compensation Committee may provide, in its discretion, that the DERs will be subject to the same forfeiture and other restrictions as a restricted incentive unit and, if so restricted, such distributions will be held, without interest, until the restricted incentive unit vests or is forfeited with the distribution being paid or forfeited at the same time, as the case may be. We intend for the issuance of the common units upon vesting of the restricted incentive units under the GP Plan to serve as a means of incentive compensation for performance and not primarily as an opportunity to participate in the equity appreciation of the common units. Therefore, under the current policy, GP Plan participants will not pay any consideration for the common units they receive, and we will receive no remuneration for the units.

EnLink Midstream, LLC Long-Term Incentive Plans

2014 Plan. Employees, non-employee directors and other individuals who provide services to us or our affiliates may be eligible to receive awards under the 2014 Plan; however, the Governance and Compensation Committee (the "Manager Committee") of the board of directors of the manager of EnLink Midstream (the "Manager Board") determines which eligible individuals receive awards under the 2014 Plan, subject to the Manager Board's approval of awards of our named executive officers. The 2014 Plan is administered by the Manager Committee and permits the grant of cash and equity-based awards, which may be awarded in the form of options, restricted unit awards, restricted incentive units, unit appreciation rights ("UARs"), DERs, unit awards, cash awards and performance awards. At the time of adoption of the 2014 Plan, 11,000,000 common units representing limited liability company interests in ENLC were initially reserved for issuance pursuant to awards under the 2014 Plan. Common units subject to an award under the 2014 Plan that are canceled, forfeited, exchanged, settled in cash or otherwise terminated, including withheld to satisfy exercise prices or tax withholding obligations, will again become available for delivery pursuant to other awards under the 2014 Plan. Of the 11,000,000 common units that may be awarded under the 2014 Plan, 8,572,402 common units remain eligible for future grants as of December 31, 2016. The long-term compensation structure is intended to align the performance of participants with long-term performance for EnLink Midstream's unitholders.

The 2014 Plan will automatically expire on February 5, 2024. The Manager Board may amend or terminate the 2014 Plan at any time, subject to any requirement of unitholder approval required by applicable law, rule or regulation. The Manager Committee may generally amend the terms of any outstanding award under the 2014 Plan at any time. However, no action may be taken by the Manager Board or the Manager Committee under the 2014 Plan that would materially and adversely affect the rights of a participant under a previously granted award without the participant's consent.

The following forms of awards may be awarded under the 2014 Plan:

- *Options.* The 2014 Plan currently permits the grant of options. These options are rights to purchase a specified number of common units of EnLink Midstream at a specified price. The exercise price of an option cannot be less than the fair market value per common unit on the date on which the option is granted and the term of the option cannot exceed ten years from the date of grant. Options will be exercisable on such terms as the Manager Committee determines. The Manager Committee will also determine the time or times at which, and the circumstances under which, an option may be exercised in whole or in part (including based on achievement of performance goals and/or future service requirements), the method of exercise, form of consideration payable in settlement, method by or forms in which common units will be delivered to participants, and whether or not an option will be in tandem with a UAR award. Under no circumstances will distributions or DERs be granted or made with respect to option awards. An option granted to an employee may consist of an option that complies with the requirements of Section 422 of the Internal Revenue Code, referred to in the 2014 Plan as an "incentive unit option." In the case of an incentive unit option granted to an employee who owns (or is deemed to own) more than 10% of the total combined voting power of all classes of units, the exercise price of the option must be at least 110% of the fair market value per common unit on the date of grant and the term of the option cannot exceed five years from the date of grant.

- *Unit Appreciation Rights or UARs.* The 2014 Plan currently permits the grant of UARs. A UAR is a right to receive an amount equal to the excess of the fair market value of one common unit of EnLink Midstream on the date of exercise over the grant price of the UAR. UARs will be exercisable on such terms as the Manager Committee determines. The Manager Committee will also determine the time or times at which and the circumstances under which a UAR may be exercised in whole or in part (including based on achievement of performance goals and/or future service requirements), the method of exercise, method of settlement, form of consideration payable in settlement, method by or forms in which common units will be delivered or deemed to be delivered to participants, whether or not a UAR shall be in tandem with an option award, and any other terms and conditions of any UAR. UARs may be either freestanding or in tandem with other awards. Under no circumstances will distributions or DERs be granted or made with respect to UAR awards.

- *Restricted Units.* The 2014 Plan currently permits the grant of restricted units. A restricted unit is a grant of a common unit of EnLink Midstream subject to a substantial risk of forfeiture, restrictions on transferability and any other restrictions determined by the Manager Committee. The Manager Committee may provide, in its discretion, that the distributions made by EnLink Midstream with respect to the restricted units will be subject to the same forfeiture and other restrictions as the restricted unit and, if so restricted, such distributions will be held, without interest, until the restricted unit vests or is forfeited with the unit distribution right being paid or forfeited at the same time, as the case may be. In addition, the Manager Committee may provide that such distributions be used to acquire additional restricted units for the participant. Under no circumstances will DERs be granted or made with respect to restricted unit awards.

- *Restricted Incentive Units.* The 2014 Plan currently permits the grant of restricted incentive units. Restricted incentive units are rights to receive cash, common units of EnLink Midstream or a combination of cash and common units of EnLink Midstream at the end of a specified period. Restricted incentive units may be subject to restrictions, including a risk of forfeiture, as determined by the Manager Committee. The Manager Committee may, in its sole discretion, grant DERs with respect to restricted incentive units. EnLink Midstream intends for the issuance of the common units upon vesting of the restricted incentive units under the 2014 Plan to serve as a means of incentive compensation for performance and not primarily as an opportunity to participate in the equity appreciation of the common units. Therefore, under the current policy, 2014 Plan participants will not pay any consideration for the common units they receive, and EnLink Midstream will receive no remuneration for the units.

- *Distribution Equivalent Rights or DERs.* The 2014 Plan currently permits the grant of DERs. DERs entitle a participant to receive cash or additional awards equal to the amount of any cash distributions made by EnLink Midstream with respect to an ENLC common unit during the period the right is outstanding. DERs may be granted as a stand-alone award or with respect to awards other than restricted units, options or UARs. Subject to Section 409A of the Internal Revenue Code, payment of a DER issued in connection with another award may be subject to the same vesting terms as the award to which it relates or different vesting terms, in the discretion of the Manager Committee.

- *Unit Awards.* The 2014 Plan currently permits the grant of unit awards, which are common units of EnLink Midstream that are not subject to vesting restrictions.

- *Cash Awards.* The 2014 Plan currently permits the grant of cash awards, which are awards denominated and payable in cash.

- *Performance Awards.* The 2014 Plan currently permits the grant of performance awards. Performance awards represent a participant's right to receive an amount of cash, common units of EnLink Midstream, or a combination of both, contingent upon the annual attainment of specified performance measures within a specified period. The Manager Committee or other committee that is intended to satisfy the requirements of Section 162(m) of the Internal Revenue Code (the "Section 162(m) Committee"), as applicable, will determine the applicable performance period, the performance goals and such other conditions that apply to each performance award. In addition, the 2014 Plan permits, but does not require, the Manager Committee or the Section 162(m) Committee, as applicable, to structure any performance award made to a covered employee as qualified performance-based compensation under Section 162(m) of the Internal Revenue Code. Section 162(m) of the Internal Revenue Code generally limits the deductibility for federal income tax purposes of annual compensation paid to certain top executives of a company to $1 million per covered employee in a taxable year (to the extent such compensation does not constitute qualified performance-based compensation under Section 162(m) of the Internal Revenue Code). Prior to the payment of any compensation based on the achievement of performance goals applicable to performance awards that are intended to provide qualified performance-based compensation under Section 162(m) of the Internal Revenue Code, the Manager Committee or the Section 162(m) Committee, as applicable, must certify in writing that applicable performance goals and any of the material terms thereof were, in fact, satisfied.

Upon a change of control of us, our general partner or EnLink Midstream and except as provided in the applicable award agreement, the Manager Committee may cause unit options and UAR grants to be vested, may cause change of control consideration to be paid in respect of some or all of such awards, or may make other adjustments (if any) that it deems appropriate with respect to such awards. With respect to other awards, upon a change of control of EnLink Midstream and except as provided in the award agreement, the Manager Committee may cause such awards to be adjusted, which adjustments may relate to the vesting, settlement or the other terms of such awards.

EnLink Midstream 2009 Long-Term Incentive Plan. The 2009 Plan provides for the award of unit options, restricted units, restricted incentive units and other awards (collectively, “Awards”). As a result of the consummation of the Business Combination, however, it is anticipated that no future Awards will be granted under the 2009 Plan. The Manager Committee administers the 2009 Plan and has the authority to grant waivers of the applicable plan terms, conditions, restrictions and limitations. As of December 31, 2016, no common units are reserved for issuance under the 2009 Plan. Each outstanding unit award under the 2009 Plan has a vesting period that was established in the sole discretion of the Manager Committee and as modified by the waivers entered into by certain individuals in connection with the Business Combination, provided that earlier vesting may arise by reason of death, disability, retirement or otherwise.

The Manager Committee may amend, modify, suspend or terminate the 2009 Plan, except that no amendment that would impair the rights of any participant to any Award may be made without the consent of such participant, and no amendment requiring unitholder approval under any applicable legal requirements will be effective until such approval has been obtained.

Performance Unit Awards. In 2015 and 2016, our general partner and the managing member of ENLC granted performance awards under the GP Plan and the 2014 Plan, respectively. The performance award agreements provide that the vesting of restricted incentive units granted under the GP Plan and 2014 Plan is dependent on the achievement of certain total shareholder return (“TSR”) performance goals relative to the TSR achievement of a peer group of companies (the “Peer Companies”) over the applicable performance period. The performance award agreements contemplate that the Peer Companies for an individual performance award (the “Subject Award”) are the companies comprising the Alerian MLP Index for Master Limited Partnerships (“AMZ”), excluding us and ENLC (collectively, “EnLink”), on the grant date for the Subject Award. The performance units will vest based on the percentile ranking of the average of our and ENLC’s TSR achievement (“EnLink TSR”) for the applicable performance period relative to the TSR achievement of the Peer Companies.

At the end of the vesting period, recipients receive distribution equivalents, if any, with respect to the number of performance units vested. The vesting of units range from 0% to 200% of the units granted depending on the EnLink TSR as compared to the Peer Companies on the vesting date. The fair value of each performance unit is estimated as of the date of grant using a Monte Carlo simulation with the following assumptions used for all performance unit grants made under the plan: (i) a risk-free interest rate based on United States Treasury rates as of the grant date; (ii) a volatility assumption based on the historical realized price volatility of our common units and the designated peer group securities; (iii) an estimated ranking of us among the designated peer group and (iv) the distribution yield. The fair value of the unit on the date of grant is expensed over a vesting period of three years.

The total value of the equity compensation granted to our executive officers generally has been awarded 50% in our restricted incentive units and 50% in restricted incentive units of EnLink Midstream, a portion of which are in the form of our performance units and EnLink Midstream for fiscal year 2016. In addition, our executive officers may receive additional grants of equity compensation in certain circumstances, such as promotions. For fiscal year 2016, our general partner granted 186,393, 158,774, 81,547, 81,547, and 98,081 performance and restricted incentive units to Barry E.

Davis, Michael J. Garberding, Steve J. Hoppe, Mac Hummel and Ben Lamb, respectively. In addition, for fiscal year 2016, the managing member of EnLink Midstream granted 161,031, 147,520, 70,451, 70,451, and 91,636 performance and restricted incentive units to Barry E. Davis, Michael J. Garberding, Steve J. Hoppe, Mac Hummel and Ben Lamb, respectively. All performance and restricted incentive units that we grant are charged against earnings according to ASC 718.

Retirement and Health Benefits. The Operating Partnership offers a variety of health and welfare and retirement programs to all eligible employees. The named executive officers are generally eligible for the same programs on the same basis as other employees of the Operating Partnership. The Operating Partnership maintains a tax-qualified 401(k) retirement plan that provides eligible employees with an opportunity to save for retirement on a tax deferred basis. In 2016, the Operating Partnership matched 100% of every dollar contributed for contributions of up to 8% of salary (not to exceed the maximum amount permitted by law) made by eligible participants. The retirement benefits provided to the named executive officers were allocated to us as general and administration expenses.

Perquisites. Our general partner generally does not pay for perquisites for any of the named executive officers, other than payment of dues, sales tax and related expenses for membership in an industry-related private lunch club (totaling less than $2,500 per year per person).

Change in Control and Severance Agreements

All of our named executive officers and certain members of senior management entered into amended change in control agreements (the "Change in Control Agreements") with the Operating Partnership as of June 15, 2015 and amended severance agreements (the "Severance Agreements" and collectively with the Change in Control Agreements, the "Agreements") with the Operating Partnership as of June 15, 2015. Additionally, as certain individuals become members of senior management, the individual may become a party to a change in control agreement and/or a severance agreement in substantially the same form as the applicable Agreement.

The Agreements restrict the officers from competing with us, as well as the Operating Partnership, EnLink Midstream, its manager, our general partner and their respective affiliates and subsidiaries (the "Company Group") during the term of employment. The Agreements also restrict the officers from disclosing confidential information of the Company Group and disparaging any member of the Company Group, in each case, during or after the term of their employment. In addition, the Agreements restrict the officers, both during their employment and for varying periods following the termination of employment, from (i) soliciting other employees to terminate their employment with any member of the Company Group or accept employment with a third party and (ii) diverting the business of a client or customer of any member of the Company Group or attempting to convert a client or customer of any member of the Company Group. The Agreements provide the Operating Partnership with equitable remedies and with the right to clawback benefits if the restrictions described in this paragraph are breached by the officer. In the event of a termination, the terminated employee is required to execute a general release of the Company Group in order to receive any benefits under the Agreements.

Under the Severance Agreements, if an officer's employment is terminated without cause (as defined in the Severance Agreement) or is terminated by the officer for good reason (as defined in the Severance Agreement), such officer will be entitled to receive (i) his or her accrued base salary up to the date of termination, (ii) any unpaid annual bonus with respect to the calendar year ending prior to the officer's termination date that has been earned as of such date, (iii) a prorated amount of the bonus (to the extent such bonus would have otherwise been earned by such officer) for the calendar year in which the termination occurs, (iv) such other fringe benefits (other than any bonus, severance pay benefit or medical insurance benefit) normally provided to employees that are already earned or accrued as of the date of termination (the foregoing items in clauses (i) - (iv) are referred to as the "General Benefits"), (v) certain outplacement services (the "Outplacement Benefits"), (vi) a lump sum severance equal to the sum of (A) the officer's then-current base salary and (B) any target bonus (as defined in the applicable Agreement) for the year that includes the date of termination (the "Severance Benefit") times two for the officer (other members of senior management are each entitled to one times the Severance Benefit), plus (vii) an amount equal to the cost to the officer to extend his or her then-current medical insurance benefits for 18 months following the effective date of the termination (the "Medical Severance Benefit").

Potential Payments Upon a Change of Control

Under the Change in Control Agreements, if, within a period that begins 120 days prior to and ends 24 months following a change in control (as defined in the Change in Control Agreement), an officer's employment is terminated without cause (as defined in the Change in Control Agreement) or is terminated by the officer for good reason (as defined in the Change in Control Agreement), such officer will be entitled to the General Benefits, the Outplacement Benefits, the Medical Severance Benefit and the Severance Benefit; provided, however, that the Chief Executive Officer would be entitled to three times the Severance Benefit, and the other officers would be entitled to two times the Severance Benefit. Other members of senior management do not receive an increase in the Severance Benefit if they are terminated in connection with a change in control.

In addition, the Agreements provide for the General Benefits upon the officer's termination of employment due to his or her death or disability (as defined in the Agreements).

The Agreements provide that an officer may only become entitled to payments under the Severance Agreement or the Change in Control Agreement, but not under both Agreements. Upon execution of a Severance Agreement, the Severance Agreement will continue in effect until (i) the first anniversary of the execution date; provided that the term will be automatically renewed for additional one-year periods beginning on the day following the first anniversary of the execution date (each, a "Renewal Date"), unless the Board or Compensation Committee, as applicable, provides the officer with written notice (a "Non-Renewal Notice") of the Operating Partnership's election not to renew the term at least 30 days prior to any Renewal Date or (ii) the termination of the officer's employment; provided that an officer's employment may not be terminated by the Operating Partnership for any reason other than cause (as defined in the Severance Agreement) for the 90-day period that follows the termination of the Severance Agreement pursuant to a Non-Renewal Notice. Upon execution of a Change in Control Agreement, the Change in Control Agreement will continue in effect until (i) the applicable Renewal Date and be automatically renewed for additional one-year periods unless the Board or Compensation Committee, as applicable, provides the officer with a Non-Renewal Notice at least 90 days prior to any Renewal Date or (ii) the termination of the officer's employment, except that a Change in Control Agreement may not be terminated for a period that begins 120 days prior to, and ends 24 months following, a change in control.

If the payments and benefits provided to an officer under the Agreements (i) constitute a "parachute payment" as defined in Section 280G of the Internal Revenue Code and exceed three times the officer's "base amount" as defined under Section 280G(b)(3) of the Internal Revenue Code, and (ii) would be subject to the excise tax imposed by Section 4999 of the Internal Revenue Code, then the officer's payments and benefits will be either (A) paid in full, or (B) reduced and payable only as to the maximum amount that would result in no portion of the payments and benefits being subject to such excise tax, whichever results in the receipt by the officer on an after-tax basis of the greatest amount (taking into account the applicable federal, state and local income taxes, the excise tax imposed by Section 4999 of the Internal Revenue Code and all other taxes, including any interest and penalties, payable by the officer).

With respect to the long-term incentive plans, the amounts to be received by our named executive officers in the event of a change of control (as defined in the long-term incentive plans) will be automatically determined based on the number of units underlying any unvested equity incentive awards held by a named executive officer at the time of a change of control. The terms of the long-term incentive plans were determined based on past practice and the applicable compensation committee's understanding of similar plans utilized by public companies generally at the time we adopted such plans. The determination of the reasonable consequences of a change of control is periodically reviewed by the applicable compensation committee.

Upon a change of control, and except as provided in the award agreement, the applicable compensation committee may cause unit options and UAR grants to be vested, may cause change of control consideration to be paid in respect of some or all of such awards, or may make other adjustments (if any) that it deems appropriate with respect to such awards. With respect to other awards, upon a change of control and except as provided in the award agreement, the applicable compensation committee may cause such awards to be adjusted, which adjustments may relate to the vesting, settlement or the other terms of such awards.

The potential payments that may be made to the named executive officers upon a termination of their employment or in connection with a change of control as of December 31, 2016 are set forth in the table in the section below entitled "Payments Upon Termination or Change in Control."

Role of Executive Officers in Executive Compensation

The Board, upon recommendation of the Compensation Committee, determines the compensation payable to each of the named executive officers. None of the named executive officers serves as a member of the Compensation Committee. Barry E. Davis, the Chief Executive Officer, reviews his recommendations regarding the compensation of his leadership team with the Compensation Committee, including specific recommendations for each element of compensation for the named executive officers. Barry E. Davis does not make any recommendations regarding his personal compensation.

Tax and Accounting Considerations

Our equity compensation grant policies have been impacted by the implementation of ASC 718, which we adopted effective January 1, 2006. Under this accounting pronouncement, we are required to value unvested unit options granted prior to our adoption of ASC 718 under the fair value method and expense those amounts in the income statement over the unit option's remaining vesting period. We have discontinued grants of unit option awards and instead grant restricted unit and restricted incentive unit awards to the named executive officers and other employees. We have structured the compensation program in a manner intended to comply with Section 409A of the Internal Revenue Code. If an executive is entitled to nonqualified deferred compensation benefits that are subject to Section 409A, and such benefits do not comply with Section 409A, then the benefits are taxable in the first year they are not subject to a substantial risk of forfeiture. In such case, the service provider is subject to regular federal income tax, interest and an additional federal income tax of 20% of the benefit includible in income.

Summary Compensation Table

The following table sets forth certain compensation information for our named executive officers.

Name and Principal Position	Year	Salary ($)	Bonus ($)(1)	Restricted Incentive Unit, and Performance Unit Awards ($)(2)	Option Awards ($)	Non-Equity Incentive Plan Compensation ($) (3)	Change in Pension value and Nonqualified Deferred Compensation Earnings ($)	All Other Compensation ($)	Total ($)
Barry E. Davis	2016	660,000	650,000	2,498,230				570,612 (4)	4,378,842
Chairman of the Board and Chief Executive Officer	2015	659,308	690,000	3,435,500	—	—	—	440,742	5,225,550
	2014	587,885	800,000	6,000,000	—	1,600,000	—	683,607	9,671,492
Michael J. Garberding	2016	462,885	416,000	3,409,650				376,304 (5)	4,664,839
President and Chief Financial Officer	2015	449,423	400,000	1,963,183	—	—	—	281,294	3,093,900
	2014	391,923	500,000	3,000,000	—	800,000	—	480,884	5,172,807
Steve J. Hoppe	2016	390,000	280,000	1,092,502				261,800 (6)	2,024,302
Executive Vice President and President of Gathering	2015	389,827	300,000	1,570,488	—	—	—	147,699	2,408,014
	2014	304,327	350,000	2,500,000	—	—	—	93,832	3,248,159
Mac Hummel	2016	390,000	225,000	1,092,502				317,871 (7)	2,025,373
Executive Vice President and President of NGL and Crude	2015	389,538	300,000	1,570,488	—	—	—	203,570	2,463,596
	2014	325,569	350,000	2,131,596	—	—	—	84,625	2,891,790
Benjamin D. Lamb (9)	2016	318,558	250,000	2,181,257				212,310 (8)	2,962,125
Executive Vice President, Corporate Development	2015	283,904	225,000	1,702,321	—	—	—	92,414	2,303,639

(1) Bonuses include all annual bonus payments. For 2015, all annual bonus payments were paid in cash. For 2016 and 2014, the named executive officers received bonuses in the form of equity awards that immediately vest. The amounts shown for 2014 represent the grant date fair value of awards computed in accordance with ASC 718. Such awards were allocated 50% in restricted units or restricted incentive units of EnLink Midstream Partners, L.P. and 50% in restricted units or restricted incentive units of EnLink Midstream, LLC.

(2) The amounts shown represent the grant date fair value of awards computed in accordance with ASC 718. See “Item 8. Financial Statements and Supplementary Data—Note 9” for the assumptions made in our valuation of such awards.
(3) Non-Equity Incentive Plan Compensation includes payments made under the cash bonus plan funded by EnLink Midstream Partners, LP in January 2014, which was designed to reward a broad base of employees for successful consummation of the transactions with Devon. These amounts were awarded in February 2014.
(4) Amount of all other compensation for Mr. Barry Davis includes professional organization and social club dues, a matching 401(k) contribution of $15,900, a 401(k) non-discretionary contribution of $11,713, DERs with respect to restricted incentive units of EnLink Midstream Partners, LP in the amount of $346,457 in 2016 and distributions on restricted units or DERs with respect to restricted incentive units and performance awards of EnLink Midstream, LLC in the amount of $196,543 in 2016.
(5) Amount of all other compensation for Mr. Michael Garberding includes professional organization and social club dues, a matching 401(k) contribution of $15,900, a 401(k) non-discretionary contribution of $11,713, DERs with respect to restricted incentive units of EnLink Midstream Partners, LP in the amount of $220,722 in 2016 and distributions on restricted units or DERs with respect to restricted incentive units of EnLink Midstream, LLC in the amount of $127,969 in 2016
(6) Amount of all other compensation for Mr. Steve Hoppe includes professional organization and social club dues, a matching 401(k) contribution of $16,135, a 401(k) non-discretionary contribution of $11,713, DERs with respect to restricted incentive units of EnLink Midstream Partners, LP in the amount of $149,248 in 2016 and DERs with respect to restricted incentive units and performance awards of EnLink Midstream, LLC in the amount of $84,704 in 2016.
(7) Amount of all other compensation for Mr. Mac Hummel includes professional organization and social club dues, a matching 401(k) contribution of $16,500, a 401(k) non-discretionary contribution of $11,713, $68,510 toward relocation and temporary housing expenses, DERs with respect to restricted incentive units of EnLink Midstream Partners, LP in the amount of $143,412 in 2016, and DERs with respect to restricted incentive units and performance awards of EnLink Midstream, LLC in the amount of $77,736 in 2016.
(8) Amount of all other compensation for Mr. Benjamin Lamb includes a matching 401(k) contribution of $16,500, a 401(k) non-discretionary contribution of $11,713, DERs with respect to restricted incentive units of EnLink Midstream Partners, LP in the amount of $117,948 in 2016, and dividends or distributions on restricted units or DERs with respect to restricted incentive units of EnLink Midstream, LLC in the amount of $66,148 in 2016.
(9) Mr. Lamb became a named executive officer in fiscal year 2015, and, therefore, summary compensation information is presented only for fiscal years 2016 and 2015.

Grants of Plan-Based Awards for Fiscal Year 2016 Table

The following tables provide information concerning each grant of an award made to a named executive officer for fiscal year 2016, including, but not limited to, awards made under the GP Plan and the 2014 Plan.

ENLINK MIDSTREAM GP, LLC—GRANTS OF PLAN-BASED AWARDS

Name	Grant Date	Estimated Future Payouts Under Equity Incentive Plan Awards: Threshold (#)	Target (#)	Maximum(#)	All Other Unit Awards: Number of Units	Grant Date Fair Value of Unit Awards
Barry E. Davis	2/19/2016				128,145 (1)	$1,040,537
	2/19/2016	—	58,248	116,496		$ 472,974
Michael J. Garberding	2/19/2016				82,712 (1)	$ 671,621
	2/19/2016	—	33,784	67,568		$ 274,326
	10/1/2016				21,139 (2)	$ 374,372
	10/1/2016	—	21,139	42,278		$ 374,372
Steve J. Hoppe	2/19/2016				55,918 (1)	$ 454,054
	2/19/2016	—	25,629	51,258		$ 208,107
Mac Hummel	2/19/2016				55,918 (1)	$ 454,054
	2/19/2016	—	25,629	51,258		$ 208,107
Benjamin D. Lamb	2/19/2016				53,588 (1)	$ 435,135
	2/19/2016	—	16,309	32,618		$ 132,429
	10/1/2016				14,092 (2)	$ 249,569
	10/1/2016	—	14,092	28,184		$ 249,569

(1) These grants include DERs that provide for distribution on restricted incentive units if made on unrestricted common units during the restriction period unless otherwise forfeited and vest 100% on January 1, 2019.
(2) These grants include DERs that provide for distribution on restricted incentive units if made on unrestricted common units during the restriction period unless otherwise forfeited and vest 100% on January 1, 2020.

ENLINK MIDSTREAM, LLC—GRANTS OF PLAN-BASED AWARDS

Name	Grant Date	Estimated Future Payouts Under Equity Incentive Plan Awards			All Other Unit Awards: Number of Units	Grant Date Fair Value of Shares Awards
		Threshold (#)	Target (#)	Maximum(#)		
Barry E. Davis	2/19/2016				110,709 (1)	$ 807,069
	2/19/2016	—	50,322	100,644		$ 366,847
Michael J. Garberding	2/19/2016				71,457 (1)	$ 520,922
	2/19/2016	—	29,187	58,374		$ 212,773
	10/1/2016				23,438 (2)	$ 392,587
	10/1/2016	—	23,438	46,876		$ 392,587
Steve J. Hoppe	2/19/2016				48,309 (1)	$ 352,173
	2/19/2016	—	22,142	44,284		$ 161,415
Mac Hummel	2/19/2016				48,309 (1)	$ 352,173
	2/19/2016	—	22,142	44,284		$ 161,415
Benjamin D. Lamb	2/19/2016				46,296 (1)	$ 337,498
	2/19/2016	—	14,090	28,180		$ 102,716
	10/1/2016				15,625 (2)	$ 261,719
	10/1/2016	—	15,625	31,250		$ 261,719

(1) These grants include DERs that provide for distribution on restricted incentive units if made on unrestricted common units during the restriction period unless otherwise forfeited and vest 100% on January 1, 2019.
(2) These grants include DERs that provide for distribution on restricted incentive units if made on unrestricted common units during the restriction period unless otherwise forfeited and vest 100% on January 1, 2020.

Outstanding Equity Awards at Fiscal Year-End Table for Fiscal Year 2016

The following tables provide information concerning all outstanding equity awards made to a named executive officer as of December 31, 2016, including, but not limited to, awards made under the GP Plan, 2014 Plan and 2009 Plan.

ENLINK MIDSTREAM GP, LLC—OUTSTANDING EQUITY AWARDS AT FISCAL YEAR-END

	Option Awards					Stock Awards			
Name	Number of Securities Underlying Unexercised Options (#) Exercisable	Number of Securities Underlying Unexercised Options (#) Exercisable	Equity Incentive Plan Awards: Number of Securities Underlying Unexercised Unearned Options (#)	Option Exercise Price ($)	Option Expiration Date	Number of Units That Have Not Vested (#)	Market Value of Units That Have Not Vested ($)(1)	Equity Incentive Plan Awards: Number of Unearned Units or Other Rights that Have Not Vested (#)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Units or Other Rights That Have Not Vested ($)
Barry E. Davis	—	—	—	—	—	95,299 (2)	1,755,408	30,680 (8)	565,126
						30,680 (4)	565,126	58,248 (9)	1,072,928
						128,145 (6)	2,360,431		
Michael J. Garberding	—	—	—	—	—	47,649 (2)	877,695	17,532 (8)	322,939
						17,532 (4)	322,939	33,784 (9)	622,301
						82,712 (6)	1,523,555	21,139 (10)	389,380
						21,139 (7)	389,380		
Steve J. Hoppe	—	—	—	—	—	39,708 (2)	731,421	14,025 (8)	258,341
						14,025 (4)	258,341	25,629 (9)	472,086
						55,918 (6)	1,030,010		
Mac Hummel	—	—	—	—	—	31,766 (2)	585,130	14,025 (8)	258,341
						4,201 (2)	77,382	25,629 (9)	472,086
						14,025 (4)	258,341		
						55,918 (6)	1,030,010		
Benjamin D. Lamb	—	—	—	—	—	7,147 (2)	131,648	11,695 (8)	215,422
						8,194 (3)	150,933	16,309 (9)	300,412
						11,695 (4)	215,422	14,092 (10)	259,575
						4,858 (5)	89,484		
						53,588 (6)	987,091		
						14,092 (7)	259,575		

(1) The closing price for the common units was $18.42 as of December 30, 2016.
(2) Restricted incentive units vest on March 7, 2017.
(3) Restricted incentive units vest on July 23, 2017.
(4) Restricted incentive units vest on January 1, 2018.
(5) Restricted incentive units vest on April 1, 2018.
(6) Restricted incentive units vest on January 1, 2019.
(7) Restricted incentive units vest on January 1, 2020.
(8) Reflects the target number of performance units granted to the named executive officers on March 17, 2015 multiplied by a performance percentage of 100%. Vesting of these awards on January 1, 2018, is contingent upon EnLink TSR performance over the applicable performance period measured against a peer group of companies.
(9) Reflects the target number of performance units granted to the named executive officers on February 19, 2016 multiplied by a performance percentage of 100%. Vesting of these awards on January 1, 2019, is contingent upon EnLink TSR performance over the applicable performance period measured against a peer group of companies.
(10) Reflects the target number of performance units granted to Mr. Lamb and Mr Garberding on October 1, 2016 multiplied by a performance percentage of 100%. Vesting of these awards on January 1, 2020, is contingent upon EnLink TSR performance over the applicable performance period measured against a peer group of companies.

ENLINK MIDSTREAM, LLC—OUTSTANDING EQUITY AWARDS AT FISCAL YEAR-END

	Option Awards					Unit Awards			
Name	Number of Securities Underlying Unexercised Options (#) Exercisable	Number of Securities Underlying Unexercised Options (#) Exercisable	Equity Incentive Plan Awards: Number of Securities Underlying Unexercised Unearned Options (#)	Option Exercise Price ($)	Option Expiration Date	Number Units That Have Not Vested (#)	Market Value of Shares or Units That Have Not Vested ($)(1)	Equity Incentive Plan Awards: Number of Unearned Units or Other Rights that Have Not Vested (#)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Units or Other Rights That Have Not Vested ($)
Barry E. Davis	—	—	—	—	—	81,967 (2)	1,561,471	27,690 (8)	527,495
						27,690 (4)	527,495	50,322 (9)	958,634
						110,709 (6)	2,109,006		
Michael J. Garberding	—	—	—	—	—	40,984 (2)	780,745	15,823 (8)	301,428
						15,823 (4)	301,428	29,187 (9)	556,012
						71,457 (6)	1,361,256	23,438 (10)	446,494
						23,438 (7)	446,494		
Steve J. Hoppe	—	—	—	—	—	34,153 (2)	650,615	12,658 (8)	241,135
						12,658 (4)	241,135	22,142 (9)	421,805
						48,309 (6)	920,286		
Mac Hummel	—	—	—	—	—	27,322 (2)	520,484	12,658 (8)	241,135
						12,658 (4)	241,135	22,142 (9)	421,805
						48,309 (6)	920,286		
Benjamin D. Lamb	—	—	—	—	—	6,148 (2)	117,119	10,074 (8)	191,910
						6,445 (3)	122,777	14,090 (9)	268,415
						10,074 (4)	191,910	15,625 (10)	297,656
						3,556 (5)	67,742		
						46,296 (6)	881,939		
						15,625 (7)	297,656		

(1) The closing price for the common units was $19.05 as of December 30, 2016.
(2) Restricted incentive units vest on March 7, 2017.
(3) Restricted incentive units vest on July 23, 2017.
(4) Restricted incentive units vest on January 1, 2018.
(5) Restricted incentive units vest on April 1, 2018.
(6) Restricted incentive units vest on January 1, 2019.
(7) Restricted incentive units vest on January 1, 2020.
(8) Reflects the target number of performance units granted to the named executive officers on March 17, 2015 multiplied by a performance percentage of 100%. Vesting of these awards on January 1, 2018, is contingent upon EnLink TSR performance over the applicable performance period measured against a peer group of companies.
(9) Reflects the target number of performance units granted to the named executive officers on February 19, 2016 multiplied by a performance percentage of 100%. Vesting of these awards on January 1, 2019, is contingent upon EnLink TSR performance over the applicable performance period measured against a peer group of companies.
(10) Reflects the target number of performance units granted to Mr. Lamb and Mr Garberding on October 1, 2016 multiplied by a performance percentage of 100%. Vesting of these awards on January 1, 2020, is contingent upon EnLink TSR performance over the applicable performance period measured against a peer group of companies.

Units Vested Table for Fiscal Year 2016

The following table provides information related to the vesting of restricted units and restricted incentive units during fiscal year ended 2016.

UNITS VESTED

	EnLink Midstream Partners, LP Unit Awards		EnLink Midstream, LLC Unit Awards	
Name	Number of Units Acquired on Vesting	Value Realized on Vesting	Number of Units Acquired on Vesting	Value Realized on Vesting
Barry E. Davis	51,546	$ 854,633 (1)	52,301	$ 789,222 (3)
Michael J. Garberding	42,913	$ 717,610 (2)	43,648	$ 662,819 (4)

(1) Consists of 51,546 units at $16.58 per unit.
(2) Consists of 30,928 units at $16.58 per unit and 11,985 units at $17.09 per unit.
(3) Consists of 52,301 units at $15.09 per unit.
(4) Consists of 31,381 units at $15.09 per unit and 12,267 units at $15.43 per unit.

Payments Upon Termination or Change of Control

The following tables show potential payments that would have been made to the named executive officers as of December 31, 2015.

Name and Principal Position	Payment Under Severance Agreements Upon Termination Other Than For Cause or With Good Reason ($)(1)	Health Care Benefits Under Change in Control and Severance Agreements Upon Termination Other Than For Cause or With Good Reason ($)(2)	Payment and Health Care Benefits Under Change in Control and Severance Agreements Upon Termination For Cause or Without Good Reason ($)(3)	Payment Under Change in Control Agreements Upon Termination and Change of Control ($)(4)	Acceleration of Vesting Under Long-Term Incentive Plans Upon Change of Control ($)(5)
Barry E. Davis *Chairman of the Board and Chief Executive Officer*	3,795,000	33,556	—	5,280,000	12,003,119
Michael J. Garberding *President and Chief Financial Officer*	2,350,000	30,682	—	2,350,000	8,642,048
Steve J. Hoppe *Executive Vice President and President of Gas Gathering, Processing and Transmission*	1,833,000	33,556	—	1,833,000	5,225,174
Mac Hummel *Executive Vice President and President of Natural Gas Liquids and Crude*	1,833,000	30,682	—	1,833,000	5,026,134
Benjamin D. Lamb *Executive Vice President*	1,621,500	33,556	—	1,311,000	5,046,685

(1) Each named executive officer is entitled to a lump sum amount equal to two times the Severance Benefit, and when applicable, the bonus amounts comprising the General Benefits will be paid if he is terminated without cause (as defined in the Severance Agreement) or if he terminates employment for good reason (as defined in the Severance Agreement), subject to compliance with certain non-competition and non-solicitation covenants described elsewhere in this Annual Report on Form 10-K. The figures shown do not include amounts of base salary previously paid or fringe benefits previously received.
(2) Each named executive officer is entitled to health care benefits equal to a lump sum payment of the estimated monthly cost of the benefits under COBRA for 18 months if he is terminated without cause (as defined in the applicable Severance Agreement or Change of Control agreement (the "Applicable Agreement") or if he terminates employment for good reason (as defined in the Applicable Agreement).
(3) Each named executive officer is entitled to his then current base salary up to the date of termination plus such other fringe benefits (other than any bonus, severance pay benefit, participation in the company's 401(k) employee benefit plan, or medical insurance benefit) normally provided to employees of the company as earned up to the date of termination if he is terminated for

cause (as defined in the Applicable Agreement) or he terminates employment without good reason (as defined in the Applicable Agreement). The figures shown do not include amounts of base salary previously paid or fringe benefits previously received.

(4) Each named executive officer is entitled to a lump sum payment equal to two times the Severance Benefit (three times in the case of the Chief Executive Officer) and when applicable, the bonus amounts comprising the General Benefits will be paid if he is terminated without cause (as defined in the Change of Control Agreement) or if he terminates employment for good reason (as defined in the Change of Control Agreement) within one-hundred and twenty (120) days prior to or two (2) years following a change in control (as defined in the Severance Agreement), subject to compliance with certain non-competition, non-solicitation and other covenants described elsewhere in this Annual Report on Form 10-K. The figures shown do not include amounts of base salary previously paid or fringe benefits previously received.

(5) Each named executive officer is entitled to accelerated vesting of certain outstanding equity awards in the event of a change of control (as defined under the long-term incentive plans). These amounts correspond to the values set forth in the table in the section above entitled Outstanding Equity Awards at Fiscal Year-End Table for Fiscal Year 2016.

Compensation of Directors for Fiscal Year 2016

DIRECTOR COMPENSATION

Name	Fees Earned or Paid in Cash ($)	Unit Awards (1) ($)	All Other Compensation (2) ($)	Total ($)
Leldon E. Echols	102,875	99,992	10,319	213,186
Kyle D. Vann	164,500	100,005	12,244	276,749
Mary P. Ricciardello	92,000	99,992	10,319	202,311
John Richels (3)	54,750	99,992	6,119	160,861
Scott A. Griffiths	144,125	100,005	12,244	256,374

(1) Mr. Echols, Vann, Griffiths, Richels and Ms. Ricciardello were granted awards of restricted incentive units of EnLink Midstream Partners, L.P. on March 7, 2016 with a fair market value of $10.85 per unit and that will vest on March 7, 2017 in the following amounts, respectively: 4,608, 9,217, 9,217, 4,608 and 4,608 Mr. Echols, Mr. Richels and Ms. Ricciardello were granted awards of restricted units of EnLink Midstream, LLC on March 7, 2016 with a fair market value of $10.10 per unit and that will vest on March 7, 2017 in the following amounts, respectively: 4,950, 4,950 and 4,950. The amounts shown represent the grant date fair value of awards computed in accordance with ASC 718. See "Item 8. Financial Statements and Supplementary Data—Note 9" for the assumptions made in our valuation of such awards. At December 31, 2016, Mr. Echols, Vann, Griffiths and Ms. Ricciardello held aggregate outstanding restricted incentive unit awards, in the following amounts, respectively: 4,608, 9,217, 9,217 and 4,608. At December 31, 2016, Mr. Echols and Ms. Ricciardello held aggregate outstanding restricted units of EnLink Midstream, LLC in the following amounts, respectively: 4,950 and 4,950.

(2) Other Compensation is comprised of DERs with respect to restricted incentive units and distributions on restricted units.

(3) Mr. Richels retired effective June 22, 2016.

Each director of EnLink Midstream GP, LLC who is not an employee of EnLink Midstream GP, LLC is paid an annual retainer fee of $50,000 and equity compensation valued at $100,000. Directors do not receive an attendance fee for each regularly scheduled quarterly board meeting but are paid $1,500 for each additional meeting that they attend. Also, an attendance fee of $1,500 is paid to each director for each committee meeting that is attended, other than the Audit Committee which pays a fee of $3,000 per meeting. The respective chairs of each committee receive the following annual fees: Audit—$12,500, Governance and Compensation—$10,000 and Conflicts—$10,000. Directors are also reimbursed for related out-of-pocket expenses. Barry E. Davis, Thomas Mitchell, Lyndon Taylor, David Hager and Sue Alberti, as officers of the Managing Member or Devon, receive no separate compensation for their respective service as directors. For directors that serve on both the boards of EnLink Midstream GP, LLC and EnLink Midstream, LLC, the above listed fees are generally allocated 75% to us and 25% to EnLink Midstream, LLC, except in the case for service on the Audit Committee, where the chair is paid a separate fee for each entity and meeting fees are split 50% to each entity.

Compensation Committee Interlocks and Insider Participation

During the fiscal year ended 2016, the Compensation Committee was composed of Scott A. Griffiths and David A. Hager. No member of the Compensation Committee during fiscal 2016 was a current or former officer or employee of EnLink Midstream GP, LLC or had any relationship requiring disclosure by us under Item 404 of Regulation S-K as adopted by the SEC. None of EnLink Midstream GP, LLC's executive officers served on the board of directors or the compensation committee of any other entity for which any officers of such other entity served either on the Board or the Compensation Committee.

The Compensation Committee of EnLink Midstream GP, LLC held six meetings during fiscal year 2016. Each member attended 100% of the meetings.

Board Leadership Structure and Risk Oversight

The Board has no policy that requires that the positions of the Chairman of the Board (the "Chairman") and the Chief Executive Officer be separate or that they be held by the same individual. The Board believes that this determination should be based on circumstances existing from time to time, including the composition, skills and experience of the Board and its members, specific challenges faced by us or the industry in which it operates, and governance efficiency. Based on these factors, the Board has determined that having Barry E. Davis serve as our Chief Executive Officer and Chairman is in the best interest of us at this time, and that such arrangement makes the best use of Mr. Davis' unique skills and experience in the industry.

The Board is responsible for risk oversight. Management has implemented internal processes to identify and evaluate the risks inherent in our business and to assess the mitigation of those risks. The Audit Committee will review the risk assessments with management and provide reports to the Board regarding the internal risk assessment processes, the risks identified and the mitigation strategies planned or in place to address the risks in the business. The Board and the Audit Committee each provide insight into the issues, based on the experience of their members, and provide constructive challenges to management's assumptions and assertions.

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

EnLink Midstream Partners, LP Ownership

The following table shows the beneficial ownership of units of EnLink Midstream Partners, LP as of February 8, 2017, held by:

- each person who beneficially owns 5% or more of any class of units then outstanding;
- all the directors of EnLink Midstream GP, LLC;
- each named executive officer of EnLink Midstream GP, LLC; and
- all the directors and executive officers of EnLink Midstream GP, LLC as a group.

The percentage of total units beneficially owned is based upon a total of 343,104,673 common units (including 221,848 restricted incentive units that are deemed beneficially owned) and 53,182,651 Series B Convertible Preferred units as of February 8, 2017.

Name of Beneficial Owner (1)	Common Units Beneficially Owned	Percentage of Common Units Beneficially Owned (2)	Series B Convertible Preferred Units Beneficially Owned	Percentage of Preferred Units Beneficially Owned	Total Units Beneficially Owned	Percentage of Total Units Beneficially Owned (3)
Devon Energy Corporation (4)	183,189,051	53.39%	—	—	183,189,051	46.23%
Enfield Holdings, L.P. (5)	—	0.00%	53,182,651	100%	53,182,651	13.42%
Barry E. Davis (6)	509,829	*	—	—	509,829	*
Michael J. Garberding (7)	130,230	*	—	—	130,230	*
Steve J. Hoppe (8)	38,894	*	—	—	38,894	*
Mac Hummel (9)	32,063	*	—	—	32,063	*
Benjamin D. Lamb (10)	11,025	*	—	—	11,025	*
Leldon E. Echols (11)	27,246	*	—	—	27,246	*
Thomas L. Mitchell	—	*	—	—	—	*
David A. Hager	—	*	—	—	—	*
Mary P. Ricciardello (12)	6,122	*	—	—	6,122	*
Scott A. Griffiths (13)	12,245	*	—	—	12,245	*
Kyle D. Vann (14)	56,490	*	—	—	56,490	*
Christopher Ortega	—	*	—	—	—	*
Tony Vaughn	—	*	—	—	—	*
Lyndon Taylor	—	*	—	—	—	*
Sue Alberti	—	*	—	—	—	*
All directors and executive officers as a group (16 persons)	851,117	0.25%	—	—	851,117	0.21%

* Less than 1%

(1) The address of each person listed above is 2501 Cedar Springs, Suite 100, Dallas, Texas 75201, except for Devon Energy Corporation, whose address is 333 W. Sheridan Avenue, Oklahoma City, Oklahoma 73102.

(2) The percentages reflected in the column below are based on a total of 343,104,673 common units, including 221,484 restricted incentive units that are deemed beneficially owned.

(3) The percentages reflected in the column below are based on a total of 396,287,324 common units, which includes the units described in (2) above, and 53,182,651 Series B Convertible Preferred units.

(4) Devon Gas Services, L.P. ("Devon Gas Services") is the record holder of 87,128,717 common units; Southwestern Gas Pipeline, L.L.C. ("Southwestern Gas") is the record holder of 7,531,883 common units; EnLink Midstream, Inc. ("EMI") is the record holder of 20,280,252 common units; and Acacia Natural Gas Corp. I, Inc. ("Acacia") is the record holder of 68,248,199 common units. As the indirect owner of (i) 100% of the outstanding limited and general partner interests in Devon Gas Services, (ii) 100% of the outstanding limited liability company interests of Southwestern Gas and (iii) 64.1% of the outstanding membership interest in EnLink Midstream, LLC (as well as 100% of the outstanding membership interest in EnLink Midstream, LLC's managing member), which is the holder of 100% of the outstanding common stock of each of EMI and Acacia, Devon Energy Corporation may be deemed to beneficially own all of the common units held by Devon Gas Services, Southwestern Gas, EMI and Acacia, as applicable.

(5) On December 6, 2015, EnLink Midstream Partners, LP and Enfield Holdings, L.P. ("Enfield Holdings") entered into that certain Convertible Preferred Unit Purchase Agreement (the "Purchase Agreement"), pursuant to which on January 7, 2016 Enfield Holdings purchased, in the aggregate, 50,000,000 Series B Convertible Preferred units. Enfield Holdings Advisors, Inc. ("Enfield Holdings Advisors") is the general partner of Enfield Holdings. Affiliates of The Goldman Sachs Group, Inc. ("GS Group") and affiliates of TPG Global, LLC own interests in Enfield Holdings Advisors. GS Group, Goldman, Sachs & Co. ("Goldman Sachs"), West Street International Infrastructure Partners III, L.P. ("WS International"), West Street European Infrastructure Partners III, L.P. ("WS European"), West Street Global Infrastructure Partners III, L.P. ("WS Global"), Broad Street Principal Investments, L.L.C. ("BS Principal"), West Street Energy Partners Offshore - B AIV-1, L.P. ("WS Offshore B"), West Street Energy Partners AIV-1, L.P. ("WS AIV"), West Street Energy Partners Offshore AIV-1, L.P. ("WS Offshore AIV"), West Street Energy Partners Offshore Holding - B AIV-1, L.P. ("WS Holdings B"), Broad Street Infrastructure Advisors III, L.L.C. ("BS Infrastructure"), Broad Street Energy Advisors AIV-1, L.L.C. ("BS Energy AIV"), and Broad Street Energy Advisors, L.L.C. ("BS Energy," and together with WS International, WS European, WS Global, BS Principal, WS Offshore B, WS AIV, WS Offshore AIV, WS Holdings B, BS Energy AIV and BS Infrastructure, the "GS Entities") are the direct or indirect beneficial owners of WSIP Egypt Holdings, LP ("WSIP") and WSEP Egypt Holdings, LP ("WSEP," and together with WSIP, GS Group,

Goldman Sachs and the GS Entities, the "GS Reporting Persons"), which hold 100 shares of common stock, and have appointed one of the two directors, of Enfield Holdings Advisors. David Bonderman and James G. Coulter are officers and sole shareholders of TPG Advisors VII, Inc. (together with the GS Reporting Persons and Messrs. Bonderman and Coulter, the "Reporting Persons"), which holds 100 shares of common stock, and has appointed one of the two directors, of Enfield Holdings Advisors. Because of the relationship between the Reporting Persons and Enfield Holdings, the Reporting Persons may be deemed to beneficially own the securities reported herein to the extent of the greater of their respective direct or indirect pecuniary interests in the profits or capital accounts of Enfield Holdings.

(6) Includes 427,862 common units owned of record by Mr. Davis and 81,967 restricted incentive units that are deemed beneficially owned. 88,652 of these common units are held by MK Holdings, LP, a family limited partnership, which Mr. Davis controls, and Mr. Davis disclaims beneficial ownership of these securities except to the extent of his pecuniary interest therein.

(7) Includes 89,246 common units owned of record by Mr. Garberding and 40,984 restricted incentive units that are deemed beneficially owned.

(8) Includes 4,741 common units owned of record by Mr. Hoppe and 34,153 restricted incentive units that are deemed beneficially owned.

(9) Includes 4,741 common units owned of record by Mr. Hummel and 27,322 restricted incentive units that are deemed beneficially owned.

(10) Includes 4,877 common units owned of record by Mr. Lamb and 6,148 restricted incentive units that are deemed beneficially owned.

(11) Includes 22,638 common units owned of record by Mr. Echols and 4,608 restricted incentive units that are deemed beneficially owned.

(12) Includes 1,514 common units owned of record by Ms. Ricciardello and 4,608 restricted incentive units that are deemed beneficially owned

(13) Includes 3,028 common units owned of record by Mr. Griffiths and 9,217 restricted incentive units that are deemed beneficially owned

(14) Includes 42,273 common units owned of record by Mr. Vann and 9,217 restricted incentive units that are deemed beneficially owned

EnLink Midstream, LLC and Devon Energy Corporation Ownership

The following table shows the beneficial ownership of the units of EnLink Midstream, LLC, as well as the beneficial ownership of shares of common stock of Devon Energy Corporation, as of February 8, 2017, held by:

- all the directors of EnLink Midstream GP, LLC;
- each named executive officer of EnLink Midstream GP, LLC; and
- all the directors and executive officers of EnLink Midstream GP, LLC as a group.

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The percentage of total common units of EnLink Midstream, LLC beneficially owned is based on a total of 180,335,062 units (including 259,686 restricted incentive units that are deemed beneficially owned) as of February 8, 2017. The percentage of total shares of Devon Energy Corporation beneficially owned is based on a total of 524,553,353 shares of common stock outstanding as of February 8, 2017.

	EnLink Midstream, LLC		Devon Energy Corporation	
Name of Beneficial Owner (1)	**Common Units Beneficially Owned**	**Percent**	**Shares of Common Stock Beneficially Owned**	**Percent**
Barry E. Davis (2)	1,912,330	1.06%	—	*
Michael J. Garberding (3)	155,743	*	500	*
Steve J. Hoppe (4)	43,452	*	15,500	*
Mac Hummel (5)	39,704	*	3,598	*
Benjamin D. Lamb (6)	7,147	*	—	*
Leldon E. Echols (7)	30,785	*	—	*
Thomas L. Mitchell	—	*	57,916	*
David A. Hager	—	*	393,604	*
Mary P. Ricciardello (8)	6,336	*	41,593	*
Scott A. Griffiths	—	*	—	*
Kyle D. Vann	—	*	—	*
Christopher Ortega	—	*	—	*
Tony D. Vaughn	—	*	181,464	*
Lyndon Taylor	—	*	221,669	*
Sue Alberti	—	*	40,601	*
All directors and executive officers as group (16 persons)	2,217,832	1.23%	956,445	0.53%

* Less than 1%.

(1) The address of each person listed above is 2501 Cedar Springs, Suite 100, Dallas, Texas 75201, except for Devon Energy Corporation, whose address is 333 W. Sheridan Avenue, Oklahoma City, Oklahoma 73102.
(2) Includes 1,817,031 common units owned of record by Mr. Davis and 95,299 restricted incentive units that are deemed beneficially owned. 1,025,000 of these common units are held by MK Holdings, LP, a family limited partnership, which Mr. Davis controls, and Mr. Davis disclaims beneficial ownership of these securities except to the extent of his pecuniary interest therein.
(3) Includes 108,094 common units owned of record by Mr. Garberding and 47,649 restricted incentive units that are deemed beneficially owned.
(4) Includes 3,744 common units owned of record by Mr. Hoppe and 39,708 restricted incentive units that are deemed beneficially owned.
(5) Includes 3,737 common units owned of record by Mr. Hummel and 35,967 restricted incentive units that are deemed beneficially owned.
(6) Includes 7,147 restricted incentive units that are deemed beneficially owned.
(7) Includes 25,835 common units owned of record by Mr. Echols and 4,950 restricted incentive units that are deemed beneficially owned.
(8) Includes 1,386 common units owned of record by Ms. Ricciardello and 4,950 restricted incentive units that are deemed beneficially owned.

Beneficial Ownership of General Partner Interest

EnLink Midstream GP, LLC owns all of our general partner interest and all of our incentive distribution rights. EnLink Midstream GP, LLC is 100% indirectly owned by EnLink Midstream, LLC.

Equity Compensation Plan Information

Plan Category	Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants, and Rights	Weighted-Average Price of Outstanding Options, Warrants and Rights	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plan (Excluding Securities Reflected in Column(a))
	(a)	(b)	(c)
Equity Compensation Plans Approved By Security Holders(1)	2,536,124 (2)	$ 7.67 (3)	6,012,007
Equity Compensation Plans Not Approved By Security Holders	N/A	N/A	N/A

(1) Our Amended and Restated Long-Term Incentive Plan was approved by our unitholders, effective April 6, 2016, for the benefit of our officers, employees and directors. See "Item 11. Executive Compensation—Compensation Discussion and Analysis." The plan, as amended, provides for the issuance of a total of 14,070,000 common units under the plan.

(2) The number of securities includes 2,024,820 restricted incentive units that have been granted under our Amended and Restated Long-Term Incentive Plan that have not vested. In addition, the number of securities includes units performance unit awards granted under the plan, assuming the target distribution at the time of vesting. Actual issuance of these performance unit awards may range from 0% to 200% of the target distribution depending on performance actually attained.

(3) The exercise prices for outstanding options under the plan as of December 31, 2016 range from $3.11 to $37.31 per unit.

Item 13. Certain Relationships and Related Transactions and Director Independence

Our General Partner

Our operations and activities are managed by, and our officers are employed by, the Operating Partnership. Our general partner does not receive any management fee or other compensation in connection with its management of our business, but it is reimbursed for all direct and indirect expenses incurred on our behalf.

Our general partner owns the general partner interest in us and all of our incentive distribution rights. Our general partner is entitled to receive incentive distributions if the amount we distribute with respect to any quarter exceeds levels specified in our partnership agreement. Under the quarterly incentive distribution provisions, generally our general partner is entitled to 13.0% of amounts we distribute in excess of $0.25 per unit, 23% of the amounts we distribute in excess of $0.3125 per unit and 48.0% of amounts we distribute in excess of $0.375 per unit.

Relationship with Devon and EnLink Midstream, LLC

ENLC indirectly owns 88,528,451 common units, representing an approximate 22.3% limited partnership interest in us as of December 31, 2016. ENLC also indirectly owns our general partner and has the power to appoint all of the officers and directors of our general partner. ENLC is managed by its managing member, which is wholly-owned by Devon. Therefore, Devon indirectly controls our general partner, which has the sole authority to manage and operate our business. Devon also directly owns 94,660,600 limited partnership units, representing an approximate 23.8% majority ownership of our outstanding equity interests as of December 31, 2016. Accordingly, through its control of our general partner, Devon effectively has the ability to veto some of our actions and to control our management.

Additionally, five of our directors, including David Hager, Thomas Mitchell, Sue Alberti, Lyndon Taylor and Tony Vaughn are officers of Devon. Those individuals do not receive separate compensation for their service on the Board, but they are entitled to indemnification related to their service as directors pursuant to the indemnification agreements as described below.

Related Party Transactions

Reimbursement of Costs by ENLC. ENLC paid us $2.3 million, $2.1 million and $1.2 million during the years ended December 31, 2016, 2015 and 2014, respectively, to cover its portion of administrative and compensation costs for officers and employees that perform services for ENLC. This reimbursement is evaluated on an annual basis. Officers and employees that perform services for ENLC provide an estimate of the portion of their time devoted to such services. A portion of their annual compensation (including bonuses, payroll taxes and other benefit costs) is allocated to ENLC for reimbursement based on these estimates. In addition, an administrative burden is added to such costs to reimburse us for additional support costs, including, but not limited to, consideration for rent, office support and information service support.

E2 Drop Down. On October 22, 2014, we acquired from EMI, a wholly-owned subsidiary of ENLC, certain equity interests in EnLink Appalachian Compression, LLC (formerly, E2 Appalachian Compression, LLC) and E2 Energy Services, LLC through its purchase of the EnLink Appalachian Units and the E2 Energy Services Units, respectively. The total consideration paid by us to EMI for such units included (i) $13.0 million in cash for the E2 Energy Services Units and (ii) $150.0 million in cash and 1,016,322 common units representing limited partner interests in us for the EnLink Appalachian Units. In April 2016, pursuant to rights in the Limited Liability Company agreement, we acquired the remaining EnLink Appalachian Units

Midstream Holdings Drop Down. On February 17, 2015, we acquired the February 2015 Transferred Interests from Acacia, a wholly-owned subsidiary of ENLC, in the February 2015 EMH Drop Down. As consideration for the February 2015 Transferred Interests, we issued 31.6 million of our common units to Acacia.

On May 27, 2015, we acquired the May 2015 Transferred Interests from Acacia in exchange for 36.6 million of our common units. After giving effect to the EMH Drop Downs, we own 100% of Midstream Holdings.

VEX Pipeline. On April 1, 2015, we acquired the VEX Interests from Devon, which are located in the Eagle Ford Shale in south Texas. We paid aggregate consideration consisting of $166.7 million in cash, 338,159 common units with an aggregate value of approximately $9.0 million and the assumption of up to $40.0 million in certain construction costs related to the VEX Interests, subject to certain adjustments set forth in the contribution agreement.

On October 29, 2015, we issued 2,849,100 common units at an offering price of $17.55 per unit to a subsidiary of ENLC for aggregate consideration of approximately $50.0 million in a private placement transaction.

In January 2016, we issued an aggregate of 50,000,000 Series B Cumulative Convertible Preferred Units (the “Preferred Units”) representing our limited partner interests to Enfield Holdings, L.P. (“Enfield”) in a private placement for a cash purchase price of $15.00 per Preferred Unit (the “Issue Price”), resulting in net proceeds of approximately $724.1 million after fees and deductions.

Commercial Arrangements

We conduct business with Devon pursuant to gathering and processing agreements described below. We also historically have maintained a relationship with Devon as a customer, as described in more detail below.

Gathering and Processing Agreements

As described elsewhere, Midstream Holdings was previously a wholly-owned subsidiary of Devon, and all of its assets were contributed to it by Devon. In connection with the consummation of the Business Combination, Midstream Holdings entered into gathering and processing agreements with certain subsidiaries of Devon pursuant to which Midstream Holdings provides gathering, treating, compression, dehydration, stabilization, processing and fractionation services, as applicable, for natural gas delivered by Devon to Midstream Holdings gathering systems in the Barnett, Cana-Woodford and Arkoma-Woodford Shales. These agreements provide Midstream Holdings with dedication of all of the natural gas owned or controlled by Devon and produced from or attributable to existing and future wells located on certain oil, natural gas and mineral leases covering lands within the acreage dedications, excluding properties previously dedicated to other natural gas gathering systems not owned and operated by Devon.

Pursuant to the gathering and processing agreements, Devon has committed to deliver specified average minimum daily volumes of natural gas to Midstream Holdings' gathering systems in the Barnett, Cana-Woodford and Arkoma-Woodford Shales during each calendar quarter for a five-year period following execution. These commitments account for substantially all of Midstream Holdings' natural gas supply and approximately 14.4% of our combined revenues, or $611.8 million for the year ended December 31, 2016, 13.4% of our combined revenues, or $596.3 million for the year ended December 31, 2015 and approximately 26.7% of our combined revenues, or $938.2 million for the year ended December 31, 2014. Devon is entitled to firm service, meaning that if capacity on a system is curtailed or reduced, or capacity is otherwise insufficient, Midstream Holdings will take delivery of as much Devon natural gas as is permitted in accordance with applicable law.

The gathering and processing agreements are fee-based, and Midstream Holdings is paid a specified fee per MMBtu for natural gas gathered on Midstream Holdings' gathering systems and a specified fee for natural gas processed. The particular fees, all of which are subject to an automatic annual inflation escalator at the beginning of each year, differ from one system to another and do not contain a fee redetermination clause.

Please see "Item 1A. Risk Factors" for a description of the risks associated with our dependence on Devon pursuant to these agreements.

Historical Customer Relationship with Devon

As noted above, we have historically maintained a customer relationship with Devon pursuant to which certain of our subsidiaries provide gathering, transportation, processing and gas lift services to Devon subsidiaries in exchange for fee-based compensation under several agreements with such Devon subsidiaries. The terms of these agreements vary, but the agreements expire between March 2017 and July 2021 and they automatically renew for month-to-month or year-to-year periods unless canceled by Devon prior to expiration. In addition, one of our subsidiaries has agreements with a subsidiary of Devon pursuant to which our subsidiary purchases and sells NGLs and pays or receives, as applicable, a margin-based fee. These NGL purchase and sale agreements have month-to-month terms. These historical agreements collectively comprise $107.2 million, $107.5 million and $112.3 million, or 2.5%, 2.4% and 3.2%, of our combined revenue for the years ended December 31, 2016, 2015 and 2014, respectively.

VEX Arrangement

We entered into to a five-year minimum transportation volume commitment with Devon related to our Victoria Express Pipeline ("VEX Pipeline"). The MVC was executed in June 2014 and the initial term expires July 2019. This agreement accounted for approximately 0.3%, 0.4% and 0.2% of our combined revenues, or $12.3 million, $17.8 million and $7.4 million, for the years ended December 31, 2016, 2015 and 2014, respectively.

Transition Services Agreement

In connection with the consummation of the Business Combination, we entered into a transition services agreement with Devon pursuant to which Devon provides certain services to us with respect to the business and operations of Midstream Holdings and we provide certain services to Devon. General and administrative expenses related to the transition service agreement were $0.3 million, $0.2 million and $3.0 million for years ended December 31, 2016, 2015 and 2014 respectively. We received $0.3 million from Devon under the transition services agreement for the years ended December 31, 2016, 2015 and 2014.

GCF Agreement

In connection with the consummation of the Business Combination, we entered into an agreement with a wholly-owned subsidiary of Devon pursuant to which Devon agreed, from and after the closing of the Business Combination, to hold for the benefit of Midstream Holdings the economic benefits and burdens of Devon's 38.75% general partner interest in Gulf Coast Fractionators in Mont Belvieu, Texas. This agreement contributed approximately $3.4 million, $13.0 million and $14.3 million to our income from unconsolidated affiliate investment for the years ended December 31, 2016, 2015 and 2014, respectively.

Lone Camp Gas Storage Agreement

In connection with the consummation of the Business Combination, we entered into an agreement with a wholly-owned subsidiary of Devon under which we will provide gas storage services at its Lone Camp storage facility. Under this agreement, the wholly-owned subsidiary of Devon will reimburse us for the expenses it incurs in providing the storage services. The gas storage agreement accounted for an immaterial amount of revenue in 2016.

Acacia Transportation Agreement

In connection with the consummation of the Business Combination, a subsidiary ours entered into an agreement with a wholly-owned subsidiary of Devon pursuant to which we provide transportation services to Devon on its Acacia line. This agreement accounted for approximately 0.4% of our combined revenues, or $15.2 million, $16.4 million and $15.1 million, for the years ended December 31, 2016, 2015 and 2014, respectively.

EnLink Oklahoma T.O. Gathering and Processing Agreement with Devon

In January 2016, in connection with the acquisition of EnLink Oklahoma T.O., we acquired a Gas Gathering and Processing Agreement with Devon Energy Production Company, L.P. ("DEPC") pursuant to which EnLink Oklahoma T.O. provides gathering, treating, compression, dehydration, stabilization, processing and fractionation services, as applicable, for natural gas delivered by DEPC. The agreement has a minimum volume commitment that will remain in place during each calendar quarter for five years and an overall term of approximately 15 years. Additionally, the agreement provides EnLink Oklahoma T.O. with dedication of all of the natural gas owned or controlled by DEPC and produced from or attributable to existing and future wells located on certain oil, natural gas and mineral leases covering land within the acreage dedications, excluding properties previously dedicated to other natural gas gathering systems not owned and operated by DEPC. DEPC is entitled to firm service, meaning a level of gathering and processing service in which DEPC's reserved capacity may not be interrupted, except due to force majeure, and may not be displaced by another customer or class of service. This agreement accounted for approximately 0.8% of our combined revenues, or $34.4 million for the year ended December 31, 2016.

Cedar Cove Joint Venture

On November 9, 2016, we formed a joint venture (the "Cedar Cove JV") with Kinder Morgan, Inc. consisting of gathering and compression assets in Blaine County, Oklahoma. Under a fifteen year, fixed-fee agreement, all gas gathered by the Cedar Cove JV will be processed at our central Oklahoma processing system. For the period from November 9, 2016 through December 31, 2016, revenue generated from processing gas from the Cedar Cove JV was classified as "Midstream services – related parties" on the consolidated statements of operations and was immaterial to our overall financial results.

Office Leases

In connection with the consummation of the Business Combination, we entered into three office lease agreements with a wholly-owned subsidiary of Devon pursuant to which we will lease office space at Devon's Bridgeport, Oklahoma City and Cresson office buildings. Rent payable to Devon under these lease agreements is $174,000, $31,000 and $66,000 respectively, on an annual basis.

Certain Relationships

From time to time, we may do business with other companies affiliated with TPG, which holds an interest in Enfield Holdings, L.P., the beneficial owner of our preferred units, or with NGP or Kinder Morgan, Inc., our joint venture partners in the Delaware Basin JV and Cedar Cove JV, respectively. We believe that any such arrangements have been or will be conducted on an arms-length basis.

Tax Sharing Agreement

In connection with the consummation of the Business Combination, we, ENLC and Devon, entered into a tax sharing agreement providing for the allocation of responsibilities, liabilities and benefits relating to any tax for which a combined tax return is due. In 2016 and 2015, we incurred approximately $2.3 million and $3.0 million, respectively, in taxes that are subject to the tax sharing agreement.

Indemnification of Directors and Officers

We have entered into indemnification agreements (the "Indemnification Agreements") with each of the General Partner's directors and executive officers (collectively, the "Indemnitees"). Under the terms of the Indemnification Agreements, we agree to indemnify and hold each Indemnitee harmless, subject to certain conditions, against any and all losses, claims, damages, liabilities, expenses (including legal fees and expenses), judgments, fines, ERISA excise taxes, penalties, interest, settlements or other amounts arising from any and all threatened, pending or completed claims, demands, actions, suits or proceedings, whether civil, criminal, administrative or investigative, and whether formal or informal and including appeals, in which the Indemnitee is involved, or is threatened to be involved, as a party or otherwise, because the Indemnitee is or was a director, manager or officer of the General Partner or us, or is or was serving at the request of the General Partner or us as a manager, managing member, General Partner, director, officer, fiduciary, or trustee of another entity, organization or person of any nature. We have also agreed to advance the expenses of an Indemnitee relating to the foregoing. To the extent that a change in the laws of the State of Delaware permits greater indemnification under any statute, agreement, organizational document or governing document than would be afforded under the Indemnification Agreements as of the date of the Indemnification Agreements, the Indemnitee shall enjoy the greater benefits so afforded by such change.

Approval and Review of Related Party Transactions

If we contemplate entering into a transaction, other than a routine or in the ordinary course of business transaction, in which a related person will have a direct or indirect material interest, the proposed transaction is submitted for consideration to the Board or our senior management, as appropriate. If the Board is involved in the approval process, it determines whether it is advisable to refer the matter to the Conflicts Committee of the Board, comprised entirely of independent directors, as constituted under our operating agreement. The Conflicts Committee operates pursuant to its written charter and our operating agreement. If a matter is referred to the Conflicts Committee, the Conflicts Committee obtains information regarding the proposed transaction from management and determines whether it is advisable to engage independent legal counsel or an independent financial advisor to advise the members of the committee regarding the transaction. If the committee retains such counsel or financial advisor, it considers the advice and, in the case of a financial advisor, such advisor's opinion as to whether the transaction is fair and reasonable to us and to our unitholders.

Director Independence

See "Item 10. Directors, Executive Officers and Corporate Governance" for information regarding director independence.

Item 14. Principal Accounting Fees and Services

Audit Fees

The fees for professional services rendered for the audit of our annual financial statements for the fiscal years ended December 31, 2016 and 2015, review of our internal control procedures for the fiscal years ended December 31, 2016 and 2015 and the reviews of the financial statements included in our Quarterly Reports on Form 10-Q or services that are normally provided by KPMG in connection with statutory or regulatory filings or engagements for each of those fiscal years were $1.9 million and $2.0 million, respectively. These amounts also included fees associated with comfort letters and consents related to debt and equity offerings.

Audit-Related Fees

KPMG did not perform any assurance and related services related to the performance of the audit or review of our financial statements for the fiscal years ended December 31, 2016 and 2015 that were not included in the audit fees listed above.

Tax Fees

KPMG did not perform any tax related services for the years ended December 31, 2016 and 2015.

All Other Fees

KPMG did not render services to us, other than those services covered in the section captioned “Audit Fees” for the fiscal years ended December 31, 2016 and 2015.

Audit Committee Approval of Audit and Non-Audit Services

All audit and non-audit services and any services that exceed the annual limits set forth in our annual engagement letter for audit services must be pre-approved by the Audit Committee. In 2016, the Audit Committee has not pre-approved the use of KPMG for any non-audit related services. The Chairman of the Audit Committee is authorized by the Audit Committee to pre-approve additional KPMG audit and non-audit services between Audit Committee meetings; provided that the additional services do not affect KPMG’s independence under applicable Securities and Exchange Commission rules and any such pre-approval is reported to the Audit Committee at its next meeting.

PART IV

Item 15. Exhibits and Financial Statement Schedules

(a) Financial Statements and Schedules

1. See "Item 8. Financial Statements and Supplementary Data."

2. Exhibits

The exhibits filed as part of this report are as follows (exhibits incorporated by reference are set forth with the name of the registrant, the type of report and registration number or last date of the period for which it was filed, and the exhibit number in such filing):

Number		Description
2.1 **	—	TOM-STACK Securities Purchase Agreement, dated as of December 6, 2015, among Tall Oak Midstream, LLC, FE-STACK, LLC, TOM-STACK Holdings, LLC, TOM-STACK, LLC, EnLink TOM Holdings, LP and EnLink Midstream, LLC and, solely for purposes of Section 6.19 thereof, EnLink Midstream Partners, LP (incorporated by reference to Exhibit 2.1 to our Current Report on Form 8-K dated December 7, 2015, filed with the Commission on December 7, 2015, file No. 001-36340).
2.2 **	—	TOMPC Securities Purchase Agreement, dated as of December 6, 2015, among TOMPC LLC, Tall Oak Midstream, LLC, EnLink TOM Holdings, LP, and EnLink Midstream, LLC and, solely for purposes of Section 6.19 thereof, EnLink Midstream Partners, LP (incorporated by reference to Exhibit 2.2 to our Current Report on Form 8-K dated December 7, 2015, filed with the Commission on December 7, 2015, file No. 001-36340).
3.1	—	Certificate of Limited Partnership of EnLink Midstream Partners, LP (incorporated by reference to Exhibit 3.1 to our Registration Statement on Form S-1, file No. 333-97779).
3.2	—	Certificate of Amendment to the Certificate of Limited Partnership of EnLink Midstream Partners, LP (incorporated by reference to Exhibit 3.2 to our Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2012, filed with the Commission on August 7, 2012, file No. 000-50067).
3.3	—	Second Amendment to the Certificate of Limited Partnership of EnLink Midstream Partners, LP (incorporated by reference to Exhibit 3.3 to our Current Report on Form 8-K dated March 6, 2014, filed with the Commission on March 11, 2014, file No. 001-36340).
3.4	—	Eighth Amended and Restated Agreement of Limited Partnership of EnLink Midstream Partners, LP, dated as of January 7, 2016 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated January 12, 2016, filed with the Commission on January 12, 2016, file No. 001-36340).
3.5	—	Certificate of Formation of EnLink Midstream GP, LLC (incorporated by reference to Exhibit 3.7 to our Registration Statement on Form S-1, file No. 333-97779).
3.6	—	Certificate of Amendment to the Certificate of Formation of EnLink Midstream GP, LLC (incorporated by reference to Exhibit 3.12 to our Registration Statement on Form S-3, file No. 333-194465).
3.7	—	Third Amended and Restated Limited Liability Company Agreement of EnLink Midstream GP, LLC, dated as of July 7, 2014 (incorporated by reference to Exhibit 3.2 to our Current Report on Form 8-K dated July 7, 2014, filed with the Commission on July 7, 2014, file No. 001-36340).
3.8	—	Amendment No. 1 to Third Amended and Restated Limited Liability Company Agreement of EnLink Midstream GP, LLC, dated as of January 7, 2016 (incorporated by reference to Exhibit 3.2 to our Current Report on Form 8-K dated January 12, 2016, filed with the Commission on January 12, 2016, file No. 001-36340).
4.1	—	Specimen Unit Certificate for Common Units (incorporated by reference to Exhibit 12 to our Registration Statement on Form 8-A, filed with the Commission on March 7, 2014, file No. 001-36340).
4.2	—	Unitholder Agreement, dated as of March 7, 2014, by and among Devon Energy Corporation, Devon Gas Corporation, Devon Gas Services, L.P., Southwestern Gas Pipeline, Inc. and EnLink Midstream Partners, LP (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K dated March 6, 2014, filed with the Commission on March 11, 2014, file No. 001-36340).
4.3	—	Indenture, dated as of March 19, 2014, by and between EnLink Midstream Partners, LP and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.2 to our Current Report on Form 8-K dated March 19, 2014, filed with the Commission on March 21, 2014, file No. 001-36340).

4.4		—	First Supplemental Indenture, dated as of March 19, 2014, by and between EnLink Midstream Partners, LP and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.3 to our Current Report on Form 8-K dated March 19, 2014, filed with the Commission on March 21, 2014, file No. 001-36340).
4.5		—	Second Supplemental Indenture, dated as of November 12, 2014, by and between EnLink Midstream Partners, LP and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.3 to our Current Report on Form 8-K dated November 6, 2014, filed with the Commission on November 12, 2014, file No. 001-36340).
4.6		—	Third Supplemental Indenture, dated as of May 12, 2015, by and between EnLink Midstream Partners, LP and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.3 to our Current Report on Form 8-K dated May 7, 2015, filed with the Commission on May 12, 2015).
4.7		—	Fourth Supplemental Indenture, dated as of July 14, 2016, by and between EnLink Midstream Partners, LP and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.2 to our Current Report on Form 8-K dated July 11, 2016, filed with the Commission on July 14, 2016, file No. 001-36340).
4.8		—	Indenture governing the Issuers' 7 ⅛% senior unsecured notes due 2022, dated as of May 24, 2012, by and among Crosstex Energy, L.P., Crosstex Energy Finance Corporation, the Guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K dated May 23, 2012, filed with the Commission on May 24, 2012, file No. 000-50067).
4.9		—	Registration Rights Agreement, dated as of January 7, 2016, by and between EnLink Midstream Partners, LP and Enfield Holdings, L.P. (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K dated January 12, 2016, filed with the Commission on January 12, 2016, file No. 001-36340).
10.1		—	Preferential Rights Agreement, dated as of March 7, 2014, by and among Crosstex Energy, Inc., EnLink Midstream Partners, LP and EnLink Midstream, LLC (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated March 6, 2014, filed with the Commission on March 11, 2014, file No. 001-36340).
10.2		—	Gas Gathering and Processing Contract-Bridgeport Plant, dated as of March 7, 2014, by and between Devon Gas Services, L.P. and EnLink Midstream Services, LLC (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K dated March 6, 2014, filed with the Commission on March 11, 2014, file No. 001-36340).
10.3		—	Gas Gathering and Processing Contract-Cana Plant, dated as of March 7, 2014, by and between Devon Gas Services, L.P. and EnLink Midstream Services, LLC (incorporated by reference to Exhibit 10.3 to our Current Report on Form 8-K dated March 6, 2014, filed with the Commission on March 11, 2014, file No. 001-36340).
10.4		—	Gas Gathering and Processing Contract-East Johnson County System, dated as of March 7, 2014, by and between Devon Gas Services, L.P. and EnLink Midstream Services, LLC (incorporated by reference to Exhibit 10.5 to our Current Report on Form 8-K dated March 6, 2014, filed with the Commission on March 11, 2014, file No. 001-36340).
10.5		—	Form of Indemnification Agreement (incorporated by reference to Exhibit 10.6 to our Current Report on Form 8-K dated March 6, 2014, filed with the Commission on March 11, 2014, file No. 001-36340).
10.6	†	—	EnLink Midstream GP, LLC Long-Term Incentive Plan, as amended and restated in 2016 (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated March 9, 2016, filed with the Commission on March 9, 2016, file No. 001-36340).
10.7	†	—	EnLink Midstream, LLC 2014 Long-Term Incentive Plan (incorporated by reference to Exhibit 4.4 to EnLink Midstream, LLC's Registration Statement on Form S-8 dated March 7, 2014, filed with the Commission on March 7, 2014, file No. 333-194395).
10.8	†	—	Form of Amended and Restated Severance Agreement (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated October 31, 2014, filed with the Commission on November 3, 2014, file No. 001-36340).
10.9		—	Form of Amended and Restated Change in Control Agreement (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated June 12, 2015, filed with the Commission June 15, 2015).
10.10	†	—	Form of Restricted Unit Agreement made under the GP Plan (incorporated by reference to Exhibit 10.9 to our Annual Report on Form 10-K for the year ended December 31, 2009, file No. 000-50067).

10.11	†	—	Form of Restricted Incentive Unit Agreement made under the GP Plan (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K dated May 9, 2013, filed with the Commission on May 13, 2013, file No. 000-50067).
10.12	†	—	Form Restricted Incentive Unit Agreement made under the 2014 Plan (Executive Form) (incorporated by reference to Exhibit 4.6 to EnLink Midstream, LLC's Registration Statement on Form S-8, file No. 333-194395).
10.13	†	—	Form of Restricted Incentive Unit Agreement made under the 2014 Plan (Employee Form) (incorporated by reference to Exhibit 4.6 to EnLink Midstream, LLC's Registration Statement on Form S-8, file No. 333-194395).
10.14		—	Credit Agreement, dated as of February 20, 2014, by and among Crosstex Energy, L.P., Bank of America, N.A., as Administrative Agent, Swing Line Lender and L/C Issuer thereunder, Citibank, N.A. and Wells Fargo Bank, National Association, as Co-Syndication Agents, Royal Bank of Canada and Bank of Montreal, as Co-Documentation Agents, and the other lenders party thereto (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated February 20, 2014, filed with the Commission on February 21, 2014, file No. 000-50067).
10.15		—	First Amendment to Credit Agreement, dated as of December 23, 2015, by and among EnLink Midstream Partners, LP, Bank of America, N.A., as Administrative Agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated December 29, 2015, filed with the Commission on December 29, 2015, file No. 001-36340).
10.16		—	Commitment Increase and Extension Agreement, dated as of February 5, 2015, by and among EnLink Midstream Partners, LP, the Lenders party thereto, and Bank of America, N.A., as an L/C Issuer, as Swing Line Lender, and as Administrative Agent for the Lenders (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated February 5, 2015, filed with the Commission on February 11, 2015, file No. 001-36340).
10.17	†	—	Form of Performance Unit Agreement made under the GP Plan (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated January 30, 2015, filed with the Commission February 5, 2015, file No. 001-36340).
10.18	†	—	Form of Performance Unit Agreement made under the 2014 Plan (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K dated January 30, 2015, filed with the Commission February 5, 2015, file No. 001-36340).
10.19	†	—	Form of Restricted Incentive Unit Agreement made under the GP Plan (incorporated by reference to Exhibit 10.3 to our Current Report on Form 8-K dated January 30, 2015, filed with the Commission February 5, 2015, file No. 001-36340).
10.20	†	—	Form of Restricted Incentive Unit Agreement made under the 2014 Plan (incorporated by reference to Exhibit 10.4 to our Current Report on Form 8-K dated January 30, 2015, filed with the Commission February 5, 2015, file No. 001-36340).
10.21		—	Convertible Preferred Unit Purchase Agreement, dated as of December 6, 2015, by and between EnLink Midstream Partners, LP and Enfield Holdings, L.P. (incorporated by reference to Exhibit 2.1 to our Current Report on Form 8-K dated December 7, 2015, filed with the Commission on December 7, 2015, file No. 001-36340).
10.22		—	Board Representation Agreement, dated as of January 7, 2016, by and among EnLink Midstream GP, LLC, EnLink Midstream Partners, LP, EnLink Midstream, Inc. and TPG VII Management, LLC (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated January 12, 2016, filed with the Commission on January 12, 2016, file No. 001-36340).
12.1	*	—	Ratio of Earnings to Fixed Charges.
21.1	*	—	List of Subsidiaries.
23.1	*	—	Consent of KPMG LLP.
31.1	*	—	Certification of the Principal Executive Officer.
31.2	*	—	Certification of the Principal Financial Officer.
32.1	*	—	Certification of the Principal Executive Officer and the Principal Financial Officer of the Partnership pursuant to 18 U.S.C. Section 1350.
101	*	—	The following financial information from EnLink Midstream Partners, LP's Annual Report on Form 10-K for the year ended December 31, 2016, formatted in XBRL (eXtensible Business Reporting Language): (i) Consolidated Statements of Operations for the years ended December 31, 2016, 2015 and 2014, (ii) Consolidated Balance Sheets as of December 31, 2016 and 2015, (iii) Consolidated Statements of Cash Flows for the years ended December 31, 2016, 2015 and 2014, (iv) Consolidated Statements of Changes in Partners' Equity for the years ended December 31, 2016, 2015 and 2014 and (v) the Notes to Consolidated Financial Statements.

* Filed herewith.

** In accordance with the instruction on Item 601(b)(2) of Regulation S-K, the exhibits and schedules to Exhibits 2.1 and 2.2 are not filed herewith. The agreements identify such exhibits and schedules, including the general nature of their content. We undertake to provide such exhibits and schedules to the Commission upon request.

† As required by Item 15(a)(3), this Exhibit is identified as a compensatory benefit plan or arrangement.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on the 15th day of February 2017.

EnLink Midstream Partners, LP
By: EnLink Midstream GP, LLC, its general partner

By: /s/ BARRY E. DAVIS
Barry E. Davis,
Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below on the dates indicated by the following persons on behalf of the Registrant and in the capacities with EnLink Midstream GP, LLC, general partner of the Registrant, indicated.

Signature	Title	Date
/s/ BARRY E. DAVIS Barry E. Davis	Chief Executive Officer and Chairman of the Board (Principal Executive Officer)	February 15, 2017
/s/ SUE ALBERTI Sue Alberti	Director	February 15, 2017
/s/ LELDON E. ECHOLS Leldon E. Echols	Director	February 15, 2017
/s/ SCOTT A. GRIFFITHS Scott A. Griffiths	Director	February 15, 2017
/s/ DAVID A. HAGER David A. Hager	Director	February 15, 2017
/s/ THOMAS MITCHELL Thomas Mitchell	Director	February 15, 2017
/s/ CHRISTOPHER ORTEGA Christopher Ortega	Director	February 15, 2017
/s/ MARY P. RICCIARDELLO Mary P. Ricciardello	Director	February 15, 2017
/s/ LYNDON TAYLOR Lyndon Taylor	Director	February 15, 2017
/s/ KYLE D. VANN Kyle D. Vann	Director	February 15, 2017

/s/ TONY VAUGHN Tony Vaughn	Director	February 15, 2017
/s/ MICHAEL J. GARBERDING Michael J. Garberding	President and Chief Financial Officer (Principal Financial and Accounting Officer)	February 15, 2017

Exhibit 12.1

RATIO OF EARNINGS TO FIXED CHARGES

	Year Ended December 31,				
	2016	2015	2014	2013	2012
	(In millions)				
Earnings before fixed charges:					
Earnings from continuing operations before non-controlling interest or tax	$ (572.0)	$ (1,378.7)	$ 331.3	$ 186.1	$ 128.3
Capitalized interest	(7.2)	(7.7)	(11.8)	—	—
Amortization of capitalized interest	1.4	0.9	0.5	—	—
Distributed income from unconsolidated affiliates	57.7	42.7	23.7	12.0	2.3
Income from unconsolidated affiliates	19.9	(20.4)	(18.9)	(14.8)	(2.0)
Non-controlling interest	8.1	0.4	0.2	—	—
Fixed charges	195.3	110.2	59.2	—	—
Total earnings before fixed charges	$ (296.8)	$ (1,252.6)	$ 384.2	$ 183.3	$ 128.6
Fixed charges:					
Interest expense	$ 188.1	$ 102.5	$ 47.4	$ —	$ —
Capitalized interest	7.2	7.7	11.8	—	—
Total fixed charges	$ 195.3	$ 110.2	$ 59.2	$ —	$ —
Ratio of earnings to fixed charges	N/A	N/A	6.5	N/A	N/A
Deficiency	$ (492.1)	$ (1,362.8)	$ —	$ —	$ —

Exhibit 21.1

LIST OF SUBSIDIARIES

Name of Subsidiary	**State of Organization**
Acacia Natural Gas, L.L.C.	Delaware
Appalachian Oil Purchasers, LLC	Delaware
Ascension Pipeline Company, LLC	Delaware
Bridgeline Holdings, L.P.	Delaware
Cedar Cove Midstream LLC	Delaware
Chandeleur Pipe Line, LLC	Delaware
Clearfield Ohio Holdings, Inc.	Ohio
Coronado Midstream LLC	Texas
Delaware G&P LLC	Delaware
EnLink Appalachian Compression, LLC	Delaware
EnLink Calcasieu, LLC	Delaware
EnLink Crude Marketing, LLC	Delaware
EnLink Crude Pipeline, LLC	Delaware
EnLink DC Gathering Company JV	Texas
EnLink Energy GP, LLC	Delaware
EnLink Gas Marketing, LP	Texas
EnLink GOM, LLC	Delaware
EnLink LIG Liquids, LLC	Louisiana
EnLink LIG, LLC	Louisiana
EnLink Louisiana Gathering, LLC	Louisiana
EnLink Matli Holdings, LLC	Delaware
EnLink Midstream Finance Corporation	Delaware
EnLink Midstream Holdings GP, LLC	Delaware
EnLink Midstream Holdings, LP	Delaware
EnLink Midstream Operating GP, LLC	Delaware
EnLink Midstream Operating, LP	Delaware
EnLink Midstream Services, LLC	Texas
EnLink NGL Marketing, LP	Texas
EnLink NGL Pipeline, LP	Texas
EnLink North Texas Gathering, LP	Texas
EnLink Ohio Compression, LLC	Delaware
EnLink Oklahoma Gas Processing, LP	Delaware
EnLink Oklahoma Pipeline, LLC	Delaware
EnLink ORV Holdings, Inc.	Delaware
EnLink Pelican, LLC	Delaware
EnLink Permian, LLC	Texas
EnLink Permian II, LLC	Texas
EnLink Processing Services, LLC	Delaware
EnLink Texas NGL Pipeline, LLC	Texas

EnLink Texas Processing, LP	Texas
EnLink Tuscaloosa, LLC	Louisiana
Howard Midstream Energy Partners, LLC	Delaware
Kentucky Oil Gathering, LLC	Delaware
LPC Crude Oil, Inc.	Texas
LPC Crude Oil II, L.L.C.	Texas
LPC Crude Oil Marketing LLC	Texas
LPC Crude Oil Pipeline, L.L.C.	Texas
M & B Gas Services, LLC	Delaware
Ohio Oil Gathering II, LLC	Delaware
Ohio Oil Gathering III, LLC	Delaware
Ohio River Valley Pipeline, LLC	Delaware
OOGC Disposal Company I, LLC	Delaware
Sabine Hub Services LLC	Delaware
Sabine Pass Plant Facility Joint Venture	Texas
Sabine Pipe Line LLC	Delaware
SWG Pipeline, L.L.C.	Texas
TOMPC LLC	Delaware
TOM-STACK, LLC	Delaware
TOM-STACK Crude, LLC	Delaware
Victoria Express Pipeline, L.L.C.	Texas
West Virginia Oil Gathering, LLC	Delaware

Exhibit 23.1

Consent of Independent Registered Public Accounting Firm

The Partners
EnLink Midstream Partners, LP

We consent to the incorporation by reference in the registration statements No.333-107025, 333-127645, 333-159140,333-188678 and 333-210641 on Form S-8, No 333-194465 and 333-199618 on Form S-3 of EnLink Midstream Partners, LP and subsidiaries of our report dated February 15, 2017, with respect to the consolidated balance sheets of EnLink Midstream Partners, LP and subsidiaries as of December 31, 2016 and 2015, and the related consolidated statements of operations, changes in partners' equity, and cash flows, for each of the years in the three-year period ended December 31, 2016, and the effectiveness of internal control over financial reporting as of December 31, 2016, which report appears in the December 31, 2016 annual report on Form 10-K of EnLink Midstream Partners, LP and subsidiaries.

Our report refers to a change in the Partnership's method of accounting for computing depreciation on certain assets.

/s/ KPMG LLP

Dallas, Texas
February 15, 2017

Exhibit 31.1

CERTIFICATIONS

I, Barry E. Davis, Chief Executive Officer and Chairman of the Board of EnLink Midstream GP, LLC, the general partner of the registrant, certify that:

1. I have reviewed this annual report on Form 10-K of EnLink Midstream Partners, LP;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

    (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ BARRY E. DAVIS
BARRY E. DAVIS,
Chief Executive Officer and Chairman of the Board
(Principal Executive Officer)

Date: February 15, 2017

Exhibit 31.2

CERTIFICATIONS

I, Michael J. Garberding, President and Chief Financial Officer of EnLink Midstream GP, LLC, the general partner of the registrant, certify that:

1. I have reviewed this annual report on Form 10-K of EnLink Midstream Partners, LP;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ MICHAEL J. GARBERDING
MICHAEL J. GARBERDING,
President and Chief Financial Officer
(Principal Financial and Accounting Officer)

Date: February 15, 2017

Exhibit 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of EnLink Midstream Partners, LP (the "Registrant") on Form 10-K for the year ended December 31, 2016 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), each of the undersigned, Barry E. Davis, Chief Executive Officer of EnLink Midstream GP, LLC, and Michael J. Garberding, Chief Financial Officer of EnLink Midstream GP, LLC, certifies, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that to his knowledge:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Registrant.

/s/ BARRY E. DAVIS
Barry E. Davis
Chief Executive Officer

Date: February 15, 2017

/s/ MICHAEL J. GARBERDING
Michael J. Garberding
Chief Financial Officer

Date: February 15, 2017

A signed original of this written statement required by Section 906 has been provided to the Registrant and will be retained by the Registrant and furnished to the Securities and Exchange Commission or its staff upon request. The foregoing certification is being furnished to the Securities and Exchange Commission as an exhibit to the Report.