UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

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

For the fiscal year ended December 31, 2015

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission file number: 000-50067

ENLINK MIDSTREAM PARTNERS, LP

(Exact name of registrant as specified in its charter)

Delaware	**16-1616605**
(State of organization)	(I.R.S. Employer Identification No.)
2501 CEDAR SPRINGS	
DALLAS, TEXAS	**75201**
(Address of principal executive offices)	(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 Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§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 $3.2 billion on June 30, 2015, based on $21.97 per unit, the closing price of the common units as reported on The New York Stock Exchange on such date.

At February 10, 2016, there were 325,183,974 common units and 7,075,433 Class C common units outstanding.

DOCUMENTS INCORPORATED BY REFERENCE:

None.

TABLE OF CONTENTS

PART I

Item 1. *Business*

General

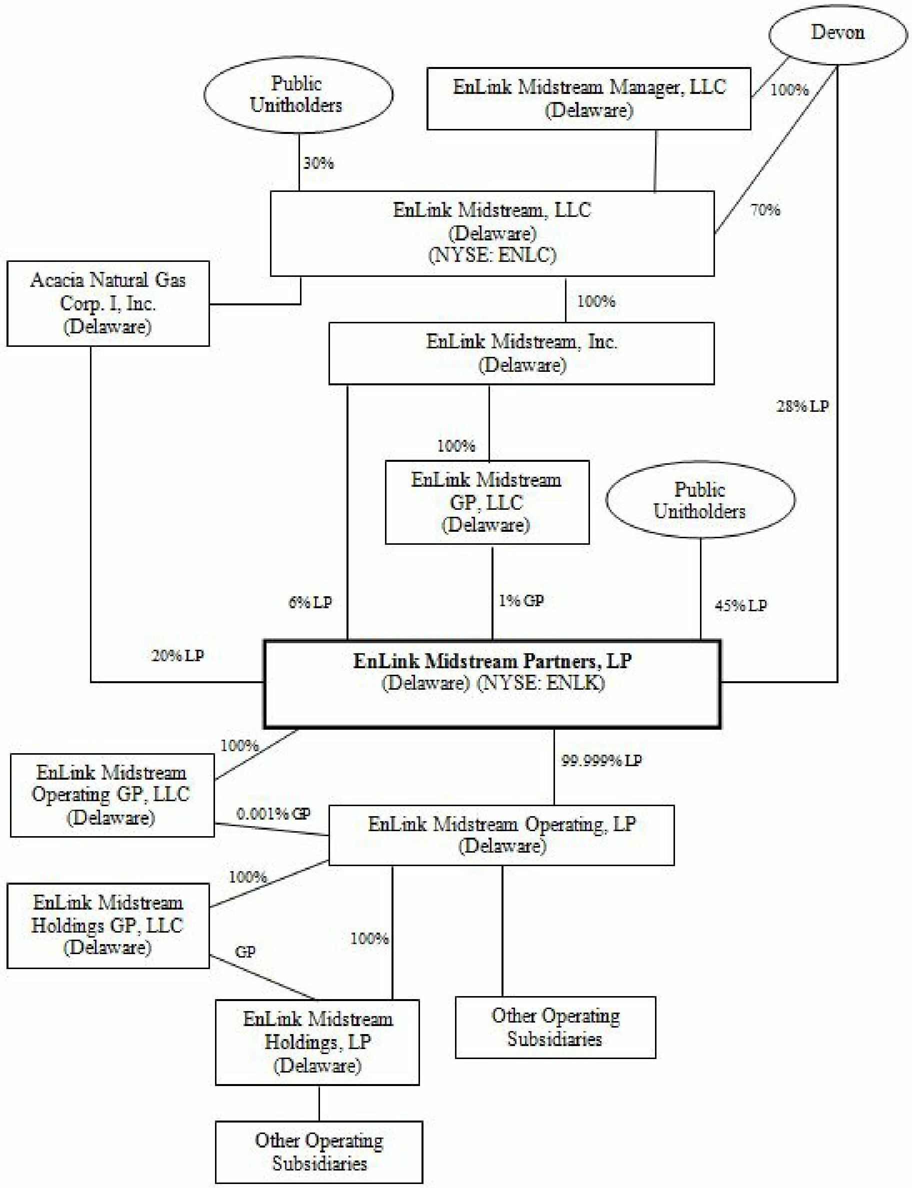
EnLink Midstream Partners, LP is a publicly traded Delaware limited partnership formed in 2002. Our common units are traded on the New York Stock Exchange ("NYSE") under the symbol "ENLK." Our business activities are conducted through our subsidiary, EnLink Midstream Operating, LP, a Delaware limited 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 Transferred Interests") to us in exchange for 31.6 million units in our partnership (the "February EMH Drop Down"). On May 27, 2015, we acquired the remaining 25% limited partner interest in Midstream Holdings (the "May Transferred Interests" and, together with the February Transferred Interests, the "Transferred Interests") from Acacia in a drop-down transaction in exchange for 36.6 million units in our partnership (the "May EMH Drop Down" and, together with the February 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.

The following diagram depicts our organization and ownership as of December 31, 2015.



On January 7, 2016, EnLink TOM Holdings, LP ("EnLink TOM Holdings"), 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. As of February 12, 2016, (a) EnLink Midstream Operating, LP, a direct subsidiary of our partnership, owns a 84% limited partnership interest in EnLink TOM Holdings, (b) EMI owns a 16% limited partnership interest in EnLink TOM Holdings and (c) EnLink Energy GP, LLC, the general partner of EnLink TOM Holdings and an indirect subsidiary of our partnership, owns the non-economic general partnership interest.

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
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").

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, brine services and marketing, to producers of natural gas, NGLs, crude oil and condensate. Our midstream energy asset network includes approximately 9,400 miles of pipelines, 16 natural gas processing plants, seven fractionators, 3.2 million barrels of NGL cavern storage, 19.1 Bcf of natural gas storage, rail terminals, barge terminals, truck terminals and a fleet of approximately 150 trucks. Our operations are based in the United States and our sales are derived 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 an end user. Our processing plants remove NGLs and CO2 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 1.3 Bcf/d, processing facilities with a total processing capacity of approximately 1.4 Bcf/d and gathering systems with total capacity of approximately 2.9 Bcf/d.
- *Oklahoma.* Our Oklahoma assets consist of processing facilities with a total processing capacity of approximately 550 MMcf/d and gathering systems with total capacity of approximately 605 MMcf/d (excluding the Oklahoma assets acquired in January 2016 discussed in Recent Growth Developments below).
- *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 1.7 Bcf/d and gathering systems with total capacity of approximately 510 MMcf/d. Our Louisiana Liquids assets consist of 660 miles of liquids transport lines and four fractionation assets with total fractionation capacity of 198 MBbls/d.

- *Crude and Condensate.* Our Crude and Condensate assets consist of approximately 350 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 101,100 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's38.75% ownership interest in Gulf Coast Fractionators ("GCF") and a 30.6% ownership interest in Howard Energy Partners ("HEP").

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, 2015 for additional information concerning Devon's business.

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 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 through the cycles in our industry.

- *Execute in our core 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 Devon's and our other 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 approximate 70% ownership interest in ENLC and approximate 28% ownership interest in us as of December 31, 2015. Approximately 50% of our gross operating margin was attributable to commercial contracts with Devon in 2015.

- *Strategically-located assets*. Our assets are strategically located in strategic producing regions with the potential for increasing throughput volume and cash flow generation. Our assets are in areas consistent with Devon's strategic focus. 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 developed or are in the process of growing our platforms in Oklahoma, in the Permian Basin in Texas and in southern Louisiana through organic development and acquisitions.

- *Stable cash flows.* Approximately 96% of our cash flows were derived from fee-based services with no direct commodity exposure during 2015. We currently have approximately eight 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 minimum volume commitments that will remain in effect for approximately three more years, as well as annual rate escalators. Additionally, our recently acquired Tall Oak assets are supported by Devon with acreage dedications and minimum volume commitments for gathering and processing on Devon's recently acquired Sooner Trend Anadarko Basin Canadian and Kingfisher Counties ("STACK") acreage. 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 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
Chisholm 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 of commitment 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 minimum volume commitment was executed in June 2014 and the initial term expires July 2019.

Recent Growth Developments

Acquisitions

Tall Oak. On January 7, 2016, we and ENLC acquired an 84% and 16% interest, respectively, in subsidiaries of Tall Oak Midstream, LLC ("Tall Oak") for $1.55 billion, subject to certain adjustments (the "Tall Oak Acquisition"). The first installment of $1.05 billion for the acquisition was paid at closing and the final installment of $500.0 million is due no later than the first anniversary of the closing date with the option to defer $250.0 million of the final installment up to 24 months following the closing date.

The first installment consisted of approximately $1.05 billion and was funded by (a) approximately $788.0 million in cash contributed by us, the majority of which was derived from the proceeds from issuance of Preferred Units (as defined under “Issuance of Preferred Units” below), and (b) (i) 15,564,009 common units representing limited liability company interests in ENLC issued directly by ENLC and (ii) approximately $19.5 million in cash contributed by ENLC.

Tall Oak's 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 have a remaining weighted-average term of approximately 15 years. Tall Oak’s 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 current capacity of 100 MMcf/d. Depending on future volume requirements, the Chisholm Plant could be expanded by an additional 600 MMcf/d for a total processing capacity of 700 MMcf/d. The plant is connected to a 200-mile, low and high-pressure gathering system with compression facilities. Additional gathering pipelines and compression facilities are currently under construction.

- *Battle Ridge Plant.* The Battle Ridge Plant, which provides us with an entry into the CNOW play, is a cryogenic gas processing plant with a current capacity of 75 MMcf/d. The plant is connected to a 175-mile, low and high-pressure gathering system with compression facilities. Additional gathering pipelines and compression facilities are currently under construction.

- *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 February 2016 and provides customers with additional operational flexibility.

Deadwood Natural Gas Processing Facility. On November 16, 2015, we acquired the remaining 50-percent ownership interest in the Deadwood natural gas processing facility from a subsidiary of Apache Corporation for approximately $40 million. The facility is located in Glasscock County, Texas in the Permian Basin. Pursuant to a 2011 agreement, we and Apache jointly funded the development of a new-build processing facility in which each company held a 50-percent undivided ownership interest. We managed the plant’s initial construction and have operated the facility since its startup. The plant has a capacity of 58 MMcf/d and is currently processing approximately 61,500 MMBtu/d. The acquisition brings our net processing capacity in the Permian Basin to 343 MMcf/d.

Acquisition of Natural Gas Gathering and Processing Assets. On October 1, 2015, we acquired all of the voting interests in DLK Wolf Midstream, LLC, a subsidiary of MRC Energy Company (“Matador”), which owns natural gas gathering and processing assets located in west Texas (the “Delaware Basin System”), for $145.3 million, subject to certain adjustments. The Delaware Basin System consists of a cryogenic gas processing plant with approximately 35 MMcf/d of inlet capacity and approximately six miles of high-pressure gathering pipeline, which connects a low-pressure gathering system to the processing plant. Matador is the largest customer on the system and has dedicated approximately 11,000 gross acres currently under development pursuant to a 15-year fixed-fee gathering and processing agreement.

Coronado Midstream. On March 16, 2015, we acquired all of the voting equity interests in Coronado Midstream Holdings LLC, the parent company of Coronado Midstream LLC (“Coronado”), which owns natural gas gathering and processing facilities in the Permian Basin, for approximately $600.3 million in cash and equity, subject to certain adjustments. The purchase price consisted of $240.3 million in cash, 6,704,285 common units and 6,704,285 of our Class C common units. Coronado operates three cryogenic gas processing plants and a gas gathering system in the North Midland Basin, including approximately 300 miles of gathering pipelines, 175 MMcf/d of processing capacity and 35,000 horsepower of compression. The Coronado system is underpinned by long-term contracts, which include the dedication of production from over 190,000 acres.

We acquired the Riptide plant located in the Permian Basin as part of the Coronado acquisition. The plant, which is under construction, will provide 100 MMcf/d of additional processing capacity and be tied to approximately 50 miles of new pipeline that is also under construction. The plant is expected to be completed in the first half of 2016.

LPC Crude Oil Marketing. On January 31, 2015, we acquired all of the voting equity interests in LPC Crude Oil Marketing LLC (“LPC”), which has crude oil gathering, transportation and marketing operations in the Permian Basin, for approximately $108.1 million. LPC is an integrated crude oil logistics service provider with operations throughout the Permian Basin. LPC's integrated logistics services are supported by 51 tractor trailers, 13 pipeline injection stations and 80 miles of crude oil gathering pipeline.

Organic Growth

HEP. During 2016, we plan to make contributions to HEP, primarily to fund our equity share of HEP's Nueva Era Pipeline. The Nueva Era Pipeline is a 50-50 joint venture between HEP and Mexico-based energy and services firm Grupo Clisa connecting HEP’s existing Webb County Hub in South Texas directly to the Mexican National Pipeline System in Monterrey, Mexico. Mexico’s Comisión Federal de Electricidad will be the foundation shipper on the approximately 200-mile, 30-inch Nueva Era Pipeline and will transport 504 MMcf/d on the system for a 25-year term.

Lobo II Natural Gas Gathering and Processing Facility. In the first quarter of 2016, we commenced construction of a new cryogenic gas processing plant and a gas gathering system in the Delaware Basin. The plant will initially provide 60 MMcf/d of processing capacity with a potential capacity of 120 MMcf/d and be tied to approximately 75 miles of new pipeline located in both in Texas and New Mexico that is also under construction. The plant and Texas portion of the pipeline are expected to be completed in the second half 2016 with the remaining New Mexico pipeline to be completed in the first quarter of 2017. The Lobo II system is supported by a long-term contract with an investment grade producer.

Ohio River Valley Condensate Stabilization Facilities. Through an agreement with Eclipse Resources, we constructed three natural gas compression and condensate stabilization facilities during late 2014 and 2015 in Harrison, Monroe and Guernsey counties in Ohio. We will begin construction on the fourth facility as needed based on available volumes.

Marathon Petroleum Joint Venture. We have entered into a series of agreements with a subsidiary of Marathon Petroleum Corporation (“Marathon Petroleum”) to create a 50/50 joint venture named Ascension Pipeline Company, LLC. This joint venture will 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. This bolt-on project to our Cajun-Sibon NGL system is supported by long-term, fee-based contracts with Marathon Petroleum. Under the arrangement, we will serve as the construction manager and operator of the pipeline project, which is expected to be operational in the first half of 2017.

Drop Downs

Midstream Holdings Drop Down. On February 17, 2015, we acquired the February Transferred Interests from Acacia, a wholly-owned subsidiary of ENLC, in the February EMH Drop Down. As consideration for the February Transferred Interests, we issued 31.6 million of our units to Acacia.

On May 27, 2015, we acquired the May Transferred Interests from Acacia in exchange for 36.6 million of our units. After giving effect to the EMH Drop Downs, we own 100% of Midstream Holdings.

VEX Pipeline. On April 1, 2015, we acquired the Victoria Express Pipeline and related truck terminal and storage assets from Devon (the “VEX Interests”), 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. 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 at the destination of the pipeline include an eight-bay truck unloading terminal, 200,000 barrels of above-ground storage and rights to barge loading docks.

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, 2015:

Gathering and Transmission Pipelines	Approximate Length (Miles)	Compression (1) (HP)	Estimated Capacity (2)	Year Ended December 31, 2015 Average Throughput (3)
Gas Pipelines				
Texas Assets:				
North Texas Assets	4,110	416,700	3,805	2,677,200
Permian Basin Assets	580	89,210	360	172,400
Oklahoma Assets:				
Cana System	440	87,500	530	380,300
Northridge System	140	13,200	75	48,300
Louisiana Assets:				
Louisiana Gas System	3,145	97,400	3,975	1,468,300
Total Gas Pipelines	8,415	704,010	8,745	4,746,500
NGL, Crude Oil and Condensate Pipelines				
Louisiana Assets:				
Louisiana Liquids Pipeline System	660	—	130,000	118,800
Crude and Condensate Assets:				
Ohio River Valley (4)	210	—	25,650	23,600
Victoria Express Pipeline	60	—	90,000	37,400
Permian Gathering (5)	80	—	70,800	64,900
Total NGL, Crude Oil and Condensate Pipelines	1,010	—	316,450	244,700

(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) Estimated capacity is comprised of trucking capacity only.

(5) Estimated capacity is comprised of 11,100 Bbls/d of pipeline capacity and 59,700 Bbls/d of trucking capacity.

Processing Facilities	Processing Capacity (MMcf/d)	Year Ended December 31, 2015 Average Throughput (MMBtu/d)
Texas Assets:		
North Texas Assets	1,070	1,000,200
Permian Basin Assets	343	222,500
Oklahoma Assets:		
Cana System	350	301,900
Northridge System	200	57,700
Louisiana Assets:		
Louisiana Gas System	1,710	506,100
Total	3,673	2,088,400

Fractionation Facilities	Estimated NGL Fractionation Capacity (MBbls/d)	Year Ended December 31, 2015 Average Throughput (MBbls/d)
Louisiana Liquids System	198	137
Gulf Coast Fractionators (1)	56	44
Texas Assets	30	— (2)
Total	284	181

(1) Volumes are shown net of our net 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 1.3 Bcf/d, processing facilities with a total processing capacity of approximately 1.4 Bcf/d and gathering systems with total capacity of approximately 2.9 Bcf/d.

- Transmission Systems. Our transmission systems in Texas include approximately 270 miles of pipeline with an aggregate capacity of approximately 1.3 Bcf/d for the year ended December 31, 2015.
    - *North Texas Assets.* Our North Texas transmission systems include the following:
        - *North Texas Pipeline.* Our North Texas Pipeline ("NTPL") is a 140-mile pipeline extending from an area near Fort Worth, Texas to a point near Paris, Texas and connects production from the Barnett Shale to markets in north Texas accessed by the Natural Gas Pipeline Company of America, LLC, Kinder Morgan, Inc., Houston Pipeline Company, L.P., Atmos Energy Corporation and Gulf Crossing Pipeline Company, LLC. The NTPL has approximately 375 MMcf/d of capacity and 18,960 horsepower of compression and, for the year ended December 31, 2015, the average throughput on the NTPL was approximately 315,700 MMBtu/d.
        - *Acacia 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, Enbridge Energy Partners, Energy Transfer Partners, Enterprise Product Partners and GDF Suez. The Acacia transmission system has approximately 920 MMcf/d of capacity and 17,000 horsepower of compression and, for the year ended December 31, 2015, average throughput was approximately 671,300 MMBtu/d. Devon is the Acacia transmission system's only customer with approximately eight 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 9 gas processing plants with total processing throughput that averaged 1,222,700 MMBtu/d for the year ended December 31, 2015 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 790 MMcf/d of processing capacity and 15 MBbls/d of NGL fractionation capacity. For the year ended December 31, 2015, throughput volumes at the Bridgeport processing facility averaged 733,900 MMBtu/d of natural gas. Devon is the Bridgeport facility's largest customer with approximately 656,500 MMBtu/d of natural gas processed for the year ended December 31, 2015, which represented approximately 90% of the total volumes processed at the facility during such period. We currently have approximately eight 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 a minimum volume

commitment from Devon that will remain in effect for approximately three more years of 650 MMcf/d of natural gas delivered to the Bridgeport processing facility 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, 2015, throughput volumes at the Silver Creek processing facility averaged 266,300 MMBtu/d of natural gas.

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

        - *Bearkat processing facility.* The Bearkat natural gas processing facility is located in Glasscock County, Texas and has a total capacity of 75 MMcf/d. The Bearkat plant averaged 28,400 MMBtu/d for the year ended December 31, 2015.

        - *Deadwood processing facility.* The Deadwood processing facility is located in Glasscock County, Texas. The Deadwood plant is supported by acreage dedication from a major producer in the Permian Basin. The Deadwood processing facility has a total capacity of 58 MMcf/d and total processing throughput that averaged 61,500 MMBtu/d for the year ended December 31, 2015.

        - *MidMar processing facilities.* The MidMar natural gas processing facility is located in the North Midland Basin in Martin County, Texas and includes two processing plants. The MidMar plants have a total of 175 MMcf/d of processing capacity with the East Plant and West Plant accounting for 100 MMcf/d and 75 MMcf/d of processing capacity, respectively. For the period March 16, 2015 to December 31, 2015, throughput volumes at the MidMar facility averaged 159,400 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 35 MMcf/d. For the period October 1, 2015 to December 31, 2015, throughput volumes at the Lobo facility averaged 21,800 MMBtu/d of natural gas.

- Gathering Systems. Our gathering systems in Texas include approximately 4,420 miles of pipeline with total throughput of approximately 1,862,600 MMBtu/d for the year ended December 31, 2015.

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

        - *Bridgeport rich gathering system.* This rich natural gas gathering system consists of approximately 2,140 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, 2015, throughput volumes on the Bridgeport rich gathering system averaged 760,400 MMBtu/d of natural gas. Devon is the largest customer on the Bridgeport rich gathering system with approximately 756,000 MMBtu/d of natural gas gathered for the year ended December 31, 2015, which represented approximately 99% of the total throughput on the system during such period. As described above, we currently have approximately eight years remaining on a fixed-fee gathering agreement with Devon pursuant to which we provide gathering services on the Bridgeport system, and such agreement includes a minimum volume commitment from Devon that will remain in effect for approximately three more years of a combined 850 MMcf/d of natural gas 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 655 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, 2015, throughput volumes on the Bridgeport lean gathering system averaged 231,800 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.

        - *East Johnson County gathering system*. This natural gas gathering system consists of approximately 290 miles of pipeline segments with approximately 33,850 horsepower of compression. Natural gas gathered on this system is delivered to intrastate pipelines without processing. For the year ended December 31, 2015, throughput volumes on the East Johnson County gathering system averaged 154,400 MMBtu/d of natural gas, which were primarily attributable to Devon. We currently have approximately eight years remaining on a fixed-fee gathering agreement pursuant to which we provide gathering services on the East Johnson County gathering system. This contractual arrangement includes a minimum volume commitment from Devon that will remain in effect for approximately three more years of 125 MMcf/d of natural gas delivered for gathering into the East Johnson County gathering system and also provides annual rate escalators.

  - *Silver Creek gathering systems*. Our Silver Creek gathering system includes two gathering systems. Our north Texas gathering system, which we refer to as NTG, consists of approximately 720 miles of gathering lines with approximately 112,874 horsepower of compression and had an average throughput of approximately 478,200 MMBtu/d for the year ended December 31, 2015. The Denton system consists of approximately 35 miles of gathering lines with approximately 29,985 horsepower of compression and had an average throughput of approximately 65,400 MMBtu/d for the year ended December 31, 2015.

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

  - *Bearkat gathering system.* The rich natural gas gathering system consists of 270 miles of high and low pressure pipeline with approximately 34,710 horsepower of compression and had an average throughput of approximately 32,300 MMBtu/d for the year ended December 31, 2015.

  - *Coronado gathering system.* The rich natural gas gathering system consists of 300 miles of high pressure pipeline with approximately 51,740 horsepower of compression. For the period March 16, 2015 to December 31, 2015, throughput volumes averaged 168,800 MMBtu/d.

  - *Lobo gathering system.* The rich natural gas gathering system consists of 10 miles of gathering pipeline with approximately 2,760 horsepower of compression. For the period October 1, 2015 to December 31, 2015, throughput volumes averaged 21,900 MMBtu/d.

Oklahoma Assets. Our Oklahoma assets consist of processing facilities with a total processing capacity of approximately 550 MMcf/d, gathering systems with total capacity of approximately 605 MMcf/d and a crude oil and condensate stabilization facility.

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

  - *Northridge processing plant.* Our Northridge processing plant has 200 MMcf/d of processing capacity. For the year ended December 31, 2015, throughput volumes at the Northridge processing facility averaged 57,700 MMBtu/d. The residue natural gas from the Northridge processing facility is delivered to Centerpoint, Enable Midstream Partners and MarkWest. In August 2014, Linn Energy acquired certain of Devon's southeastern Oklahoma assets thereby becoming the largest customer of the Northridge processing facility. In connection with this acquisition, effective December 1, 2014, Devon assigned, and Linn Energy assumed, all right, title and interest in Devon's fixed-fee gathering and processing agreement with us pursuant to which we provide processing services for natural gas delivered to the Northridge processing facility. This contractual arrangement includes a minimum volume commitment that will remain in effect for approximately three more years of 40 MMcf/d of natural gas delivered to the Northridge processing facility and also provides annual rate escalators.

  - *Cana processing facilities.* Our Cana processing facilities include a multi-train 350 MMcf/d cryogenic processing plant and a crude oil and condensate stabilization facility. For the year ended December 31, 2015, throughput volumes at the Cana processing facility averaged 301,900 MMBtu/d. 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 eight 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. This contractual arrangement includes minimum volume commitment from Devon that will remain in effect for approximately three more years of 330 MMcf/d of natural gas delivered to the processing facility and provides annual rate escalators.

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

  - *Cana gathering system*. Our Cana gathering system is located in the Cana-Woodford Shale in West Central Oklahoma and includes approximately 440-mile gathering system with approximately 87,500 horsepower of compression. For the year ended December 31, 2015, the Cana system gathered approximately 380,300 MMBtu/d of gas. Devon is the primary customer of the Cana gathering system and, as described above, has entered into a fixed-fee gathering and processing agreement with us that covers gathering services on the Cana gathering system.

- *Northridge gathering system.* Our Northridge gathering system is located in the Arkoma-Woodford Shale in Southeastern Oklahoma and includes approximately 140-mile gathering system with approximately 13,200 horsepower of compression. For the year ended December 31, 2015, the Northridge system gathered 48,300 MMBtu/d of gas. Linn Energy is the only customer on the Northridge gathering system and, as described above, is party to a fixed-fee gathering and processing agreement with us that covers gathering services on the Northridge gathering system.

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 1.7 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 1.7 Bcf/d and underground gas storage of 19.1 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 the south, 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, 2015, throughput volumes on the gathering system averaged 881,000 MMBtu/d of natural gas and throughput volumes on the transmission system averaged 587,300 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 506,100 MMBtu/d for the year ended December 31, 2015.

    - *Plaquemine Processing Plant.* The Plaquemine processing plant has 110 MMcf/d of processing capacity. For the year ended December 31, 2015, throughput volumes of the Plaquemine processing plant averaged 161,400 MMBtu/d of natural gas.

    - *Gibson Processing Plant.* The Gibson processing plant has 225 MMcf/d of processing capacity. For the year ended December 31, 2015, throughput volumes of the Gibson processing plant averaged 38,500 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, 2015, the plant processed approximately 306,200 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. The plant has a net capacity with respect to our interest of approximately 300 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 10.2 Bcf. This facility is designed for injecting pipeline quality gas into storage or withdrawing stored gas for delivery by pipeline. This storage facility is expected to go into service during 2016. The storage facility includes three compressors with total of 9,637 horsepower.

  - *Sorrento Gas Storage Facility.* The storage facility is located in Assumption Parish, Louisiana and has a total capacity of 8.9 Bcf and is currently in service. 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 660 miles of liquids transport lines, processing and fractionation assets and underground storage.
    - *Cajun-Sibon Pipeline System.* The Cajun-Sibon pipeline system consists of approximately 660 miles of raw make NGL pipelines with a current system capacity of approximately 130,000 Bbls/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 137,500 Bbls/d for the year ended December 31, 2015.
        - *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 has a capacity of approximately 100,000 Bbls/d, and 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 plant fractionated 59,200 Bbls/d for the year ended December 31, 2015.
        - *The Plaquemine Gas Processing Plant.* The Plaquemine Gas Processing Plant also has a fractionator with a capacity of 10,800 Bbls/d of raw-make NGL products, and total volume for fractionated liquids at Plaquemine which averaged approximately 2,000 Bbls/d for the year ended December 31, 2015.
        - *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 49,300 Bbls/d of liquids for the year ended December 31, 2015.
        - *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 27,000 Bbls/d for the year ended December 31, 2015.
    - *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 350 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 101,100 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 2 newly purchased trailers for hauling NGL volumes with a current capacity of 25,650 Bbls/d. Total crude oil and condensate handled averaged approximately 23,600 Bbls/d for the year ended December 31, 2015. We have eight existing brine disposal wells with an injection capacity of approximately 4,000 Bbls/d and an average disposal rate of 3,900 Bbls/d for the year ended December 31, 2015. 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 71,000 Bbls/d. Their integrated logistics services are supported by 51 tractor trailers, 13 pipeline injection stations and 80 miles of crude oil gathering pipeline. Total crude oil and condensate handled for the period February 1, 2015 to December 31, 2015 averaged approximately 70,900 Bbls/d.

- *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 37,400 Bbls/d for the year ended December 31, 2015.

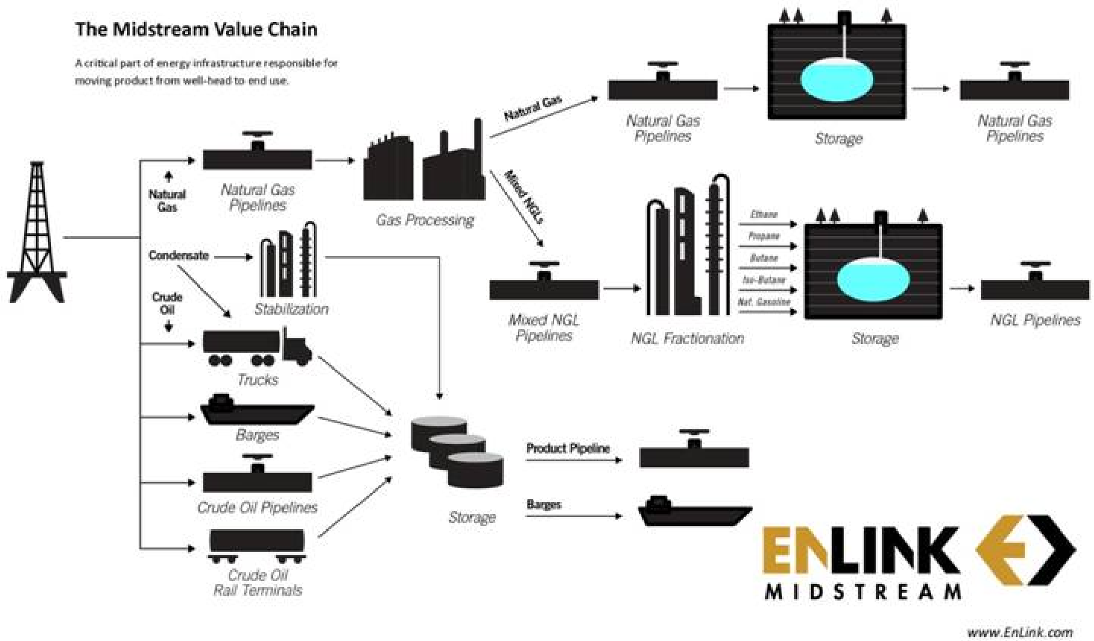
Corporate. Our Corporate assets primarily consist of a contractual right to the benefits and burdens associated with Devon's 38.75% ownership interest in GCF and a 30.6% ownership interest in HEP.

- *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 22.50% 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 44,000 Bbls/d of liquids for the year ended December 31, 2015.

- *Howard Energy Partners.* HEP owns and operates over 500 miles of pipeline and a 200 MMcf/d processing plant, serving production from the Eagle Ford, Escondido, Olmos, Pearsall and other formations in south Texas and pursues a growth strategy focused on the needs of south Texas producers. HEP's system has 145 MMcf/d of amine treating capacity and more than 9,000 horsepower of compression. In addition, HEP has a 10 MBbls/d stabilizer in Live Oak County and a 220 MBbls/d liquids storage terminal near Brownsville, Texas. HEP also owns more than 100 miles of natural gas gathering pipeline in Lycoming and Bradford counties in Pennsylvania and a 230 MBbls/d liquids storage terminal near Port Arthur, Texas. As of December 31, 2015, we owned a 30.6% interest in HEP and accounted for this investment under the equity method of accounting. Alinda Capital Partners owns a 59% capital interest in HEP.

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. Also, 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 NYMEX related to our natural gas purchases. Through these transactions, we seek to maintain a position that is balanced between purchases, on the one hand, and sales or future delivery obligations, on the other hand. 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 the relationship between Devon and Midstream Holdings, we will not compete for the portion of Devon's existing operations subject to existing acreage dedication and for which Midstream Holdings will provide midstream services. For areas where acreage is not dedicated to Midstream Holdings, 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 a minimum volume commitment 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 declines in 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, 2015 and 2014, Devon represented16.6% and 30.6%, respectively, of our consolidated revenues and Dow Hydrocarbons & Resources LLC (“Dow Hydrocarbons”) represented 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. For the foreseeable future, we expect our profitability to be substantially dependent on Devon. Further, the loss of 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 Dow Hydrocarbons are material to our total gross operating margin.

Regulation

Interstate Natural Gas Pipelines Regulation. We own interstate natural gas pipelines that are subject to regulation by the Federal Energy Regulatory Commission (“FERC”) under the Natural Gas Act (“NGA”). Under the NGA, FERC has authority to regulate natural gas companies that provide natural gas pipeline transportation services in interstate commerce. FERC regulation extends to such matters as the following:

- rates, services and terms and conditions of service;
- the certification and construction of new facilities;
- the extension or abandonment of services and facilities;
- the maintenance of accounts and records;
- the acquisition and disposition of facilities;
- maximum rates payable for certain services;
- the initiation and discontinuation of services;
- internet posting requirements for available capacity, discounts and other matters;
- pipeline segmentation to allow multiple simultaneous shipments under the same contract;
- capacity release to create a secondary market for transportation services;

- relationships between affiliated companies involved in certain aspects of the natural gas business;
- market manipulation in connection with interstate sales, purchases or transportation of natural gas and NGLs; and
- participation by interstate pipelines in cash management arrangements.

Natural gas companies are prohibited from charging rates that have been determined not to be just and reasonable by FERC. In addition, FERC prohibits natural gas companies from unduly preferring or unreasonably discriminating against any person with respect to pipeline rates or terms and conditions of service.

The rates and terms and conditions for our interstate pipeline services are set forth in FERC-approved tariffs. Pursuant to FERC's jurisdiction over rates, existing rates may be challenged by complaint or by action of FERC under Section 5 of the NGA, and proposed rate increases may be challenged by protest. The outcome of any successful complaint or protest against our rates could have an adverse impact on revenues associated with providing transportation service. Various aspects of an interstate pipeline's rates can be challenged in a rate proceeding at the FERC.

For example, one issue relates to FERC's policy regarding allowances for income taxes in determining a regulated entity's cost of service. FERC's income tax allowance policy is the result of substantial and ongoing litigation regarding whether and to what extent regulated companies are able to recover an allowance for income taxes in rates. Adverse rulings on ratemaking issues such as this one can have detrimental effects on certain rates that can be charged by interstate pipelines.

Interstate natural gas pipelines regulated by the FERC are required to comply with numerous regulations related to standards of conduct, market transparency, and market manipulation. The FERC's standards of conduct regulate the manner in which interstate natural gas pipelines may interact with their marketing affiliates (unless the FERC has granted a waiver of such standards). The FERC's market oversight and transparency regulations require annual reports of purchases or sales of natural gas meeting certain thresholds and criteria and certain public postings of 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. Should we fail to comply with all applicable FERC-administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines.

We also transport gas in interstate commerce that is subject to FERC jurisdiction under Section 311 of the NGPA. The maximum rates for services provided under Section 311 of the NGPA may not exceed a "fair and equitable rate," as defined in the NGPA. The rates are generally subject to review every five years by FERC or by an appropriate state agency. The inability to obtain approval of rates at acceptable levels could result in refund obligations, the inability to achieve adequate returns on investments in new facilities and the deterrence of future investment or growth of the regulated facilities.

Interstate Liquids Pipelines Regulation. We own certain liquids and crude oil pipelines providing common carrier interstate service that are subject to regulation by FERC under the Interstate Commerce Act ("ICA"), the Energy Policy Act of 1992 and related rules and orders. These assets include our ORV, VEX 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. For the five-year period beginning in 2010, FERC established an annual index adjustment equal to the change in the producer price index for finished goods plus 2.65%. 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%. Under FERC's regulations, liquids pipelines can request a rate increase that exceeds the rate obtained through application of the indexing methodology by using a cost-of-services 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 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 could require the payment of 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.

The rates charged by our interstate liquids pipelines may also be affected by the ongoing litigation regarding FERC's income tax allowance policy. 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. Our intrastate natural gas pipeline operations are subject to regulation by various agencies of the states in which they are located. Most states have agencies that possess the authority to review and authorize natural gas transportation transactions and the construction, acquisition, abandonment and interconnection of physical facilities. Some states also have state agencies that regulate transportation rates, service terms and conditions and contract pricing to ensure their reasonableness and to ensure that the intrastate pipeline companies that they regulate do not discriminate among similarly situated customers.

The FERC's anti-manipulation rules apply to non-jurisdictional entities to the extent the activities are conducted "in connection with" gas sales, purchases or transportation subject to FERC jurisdiction. The new anti-manipulation rules do not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering, but only to the extent such transactions do not have a "nexus" to jurisdictional transactions. As noted above, the FERC's civil penalty authority under EPAct 2005 would apply to violations of these rules to the extent applicable to our intrastate natural gas services.

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 the regulatory regime varies from state to state, 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 a pipeline's status as a gatherer not subject to FERC jurisdiction. State regulation of gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements, and in some instances complaint-based rate regulation.

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.

The FERC's anti-manipulation rules apply to non-jurisdictional entities to the extent the activities are conducted "in connection with" gas sales, purchases or transportation subject to FERC jurisdiction. The new anti-manipulation rules do not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering, but only to the extent such transactions do not have a "nexus" to jurisdictional transactions. As noted above, the FERC's civil penalty authority under EPAct 2005 would apply to violations of these rules to the extent applicable to our natural gas gathering services.

Intrastate Natural Gas Storage Regulation. The storage field's injection and withdrawal wells used in association with the Acacia system, along with water disposal wells located at the Bridgeport processing facility, are under the jurisdiction of the Texas Railroad Commission ("TRRC"). Regulatory requirements for these wells involve monthly and annual reporting of the natural gas and water disposal volumes associated with the operation of such wells, respectively. Results of periodic mechanical integrity tests run on these wells must also be reported to the TRRC.

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 and cost of pipeline transportation. As noted above, the price and terms of access to pipeline transportation are subject to extensive federal and state regulation. FERC is continually proposing and implementing new rules and regulations affecting those segments of the natural gas and NGL industries, most notably interstate natural gas transmission companies and NGL pipeline companies that remain subject to FERC's jurisdiction. These initiatives also may affect the intrastate transportation of natural gas and NGLs under certain circumstances. We cannot predict the ultimate impact of these regulatory changes on our natural gas and NGL marketing operations, but we do not believe that we will be affected by any such FERC action in a manner that is materially different from the natural gas and NGL marketers with whom we compete.

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 U.S. Department of Transportation ("DOT"). DOT's Pipeline Hazardous Material Safety Administration ("PHMSA"), acting through the Office of Pipeline Safety ("OPS"), administers the national regulatory program to assure the safe transportation of natural gas, petroleum and other hazardous materials by pipeline. OPS develops regulations and other approaches to risk management to assure safety in design, construction, testing, operation, maintenance and emergency response of pipeline facilities. The main bodies of safety regulations that cover our operations are set forth at 49 CFR Parts 192 (covering pipelines that transport natural gas) and 195 (pipelines that transport crude oil and condensate, carbon dioxide, NGL and petroleum products). In addition to recordkeeping and reporting requirements, amendments to 49 CFR Part 192 and 195 created the Pipeline Integrity Management in High Consequence Areas requiring operators of transmission pipelines to ensure the integrity of their pipelines through hydrostatic pressure testing, the use of in-line inspection tools or through risk-based direct assessment techniques. In January 2012, the President signed into law the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 which increases potential penalties for pipeline safety violations, gives new rulemaking authority to DOT with respect to shut-off valves on transmission pipeline facilities constructed or entirely replaced after the rule is promulgated, requires DOT to revise incident notification guidance and imposes new records requirements on pipeline owners and operators. This legislation also requires DOT to study and report to Congress on other areas of pipeline safety, including expanding the reach of the integrity management regulations beyond high consequences areas, but restricts DOT from promulgating expanded integrity management rules during the review period and for a period following submission of its report to Congress unless the rulemaking is needed to address a present condition that poses a risk to public safety, property or the environment. PHMSA issued a final rule effective October 25, 2013 that implemented aspects of the new legislation. Among other things, the final rule increases the maximum civil penalties for violations of pipeline safety statutes or regulations, broadens PHMSA's authority to submit information requests, and provides additional detail regarding PHMSA's corrective action authority. Additionally, PHMSA issued an Advisory Bulletin in May 2012, which advised pipeline operators of anticipated changes in annual reporting requirements and that if they are relying on design, construction, inspection, testing or other data to determine the pressures at which their pipelines should operate, the records of that data 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 to meet the demands of such pressures could significantly increase our costs. Additionally, failure to locate such records or verify maximum pressures could result in reductions of allowable operating pressures, which would reduce available capacity on our pipelines. A December 2012 PHMSA Advisory Bulletin provides further clarity on the reporting requirements of the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, describing a general requirement that pipeline owners or operators report an exceedance of the maximum allowable operating pressure or allowable build-up for pressure-limiting or control devices within five days of the date that the exceedance occurs. 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 the PHMSA or state requirements will not have a material adverse effect on our results of operations or financial positions.

As a follow-up to a PHMSA inspection of facilities and records for our ORV pipeline in December 2012, 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 is not yet scheduled and 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 Part 195-compliant integrity management program, including hydrostatic testing and a leak detection and repair program.

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 mining the failed cavern. We also filed a claim with our insurers, which our insurers denied. We disputed the denial and intend to proceed with litigation against 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.

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 petroleum. 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 release 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 cost items 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. In 2015, we incurred approximately $1.5 million in clean-up and remediation expenses related to a spill in Ohio. We provided required notifications to applicable state and federal agencies relating to the spill. This matter has been closed, and no additional expenses are expected. Additionally, we have incurred approximately $1.8 million to clean-up a spill that occurred in our West Virginia operations. We are working with state and federal agencies relating to this spill, including providing any required notifications and responding to any inquiries. We will continue to work with state and federal agencies to bring this matter to a close.

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 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. In the event of future increases in environmental costs, we may be unable to pass on those cost increases to our customers. A discharge of hazardous substances or solid wastes into the environment could, to the extent losses related to the event are not insured, subject 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, groundwater and surface water and/or include measures to prevent and control pollution may pose the highest potential cost to our industry sector. These laws and regulations generally regulate the generation, storage, treatment, transportation and disposal of solid and hazardous wastes and may require investigatory and corrective actions at facilities where such waste 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 liable 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 or state 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 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 materials may have been released on or under various properties owned, leased or operated by us during the operating history of those facilities. In addition, a number of these properties may have been operated by third parties over whose operations practices we had no control. These properties and materials 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 property contamination, if present, including groundwater contamination, or to take action to prevent future contamination.

Air Emissions. Many of our current and future operations are subject to the federal Clean Air Act and comparable state laws and regulations. These laws and regulations regulate emissions of air pollutants from various industrial sources, including our facilities, and impose various controls together with monitoring and reporting requirements. Pursuant to these laws and regulations, we may be required to obtain environmental agency 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 or additional monitoring requirements 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. Although we can give no assurances, we believe such requirements will not have a material adverse effect on our financial condition or operating results, 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, 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 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 June 2, 2015, the Circuit Court of Appeals for the D.C. Circuit denied petitions for review filed by Devon, Texas industry trade groups and the State of Texas challenging the nonattainment designation of Wise County under the 2008 ozone NAAQS. Consequently, Wise County is now required to meet the 2008 revised ozone NAAQS.

On April 17, 2012, the EPA approved final rules under the Clean Air Act that establish new air emission controls for oil and natural gas production, pipelines and processing operations. These rules became effective on October 15, 2012. For new or reworked hydraulically-fractured gas wells, the rules require the use of green completions by all such wells except wildcat (exploratory) and delineation gas wells and low reservoir pressure non-wildcat and non-delineation gas wells. The rules also establish specific new requirements regarding emissions from wet seal and reciprocating compressors at production facilities, gathering systems, boosting facilities and onshore natural gas processing plants, and from pneumatic controllers and storage vessels at production facilities, gathering systems, boosting facilities and onshore natural gas processing plants. In addition, the rules revise existing requirements for volatile organic compound 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. 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.

Compliance with these and other modified or newly issued rules could result in an increase in 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.

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 has adopted regulations under existing provisions of the federal Clean Air Act, that establish 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. 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 will be open for signing on April 22, 2016 and will require 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.

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. 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, financial position, results of operations and prospects.

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. The EPA and the U.S. Army Corps of Engineers recently adopted a rule to clarify the meaning of the term “waters of the United States” with respect to federal jurisdiction. Many interested parties believe that the proposed rule expands federal jurisdiction under the Clean Water Act. Regulations promulgated pursuant to these laws 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 thereunder and that continued compliance with such existing permit conditions will not have a material effect on our results of operations.

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 SDWA. 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 including Texas and Ohio where we operate brine disposal wells, 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. 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. For example, in August 2015, the EPA proposed updates to new source performance standard requirements that would impose more stringent controls on methane, a greenhouse gas ("GHG"), and volatile organic compounds emissions from oil and gas development and production operations, including hydraulic fracturing and other well completion activity. Congress from time to time has considered the adoption of legislation to provide for federal regulation of hydraulic fracturing under the SDWA and to require disclosure of the chemicals used in the hydraulic fracturing process. Some states have adopted, and other states are considering adopting, legal requirements that could impose more stringent permitting, public disclosure or well construction requirements on hydraulic fracturing activities. Local governments have also adopted and may seek to adopt further ordinances regulating, within their jurisdictions, the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular, in some cases banning hydraulic fracturing entirely. Other governmental agencies, including the U.S. Department of Energy and the EPA, have evaluated or are evaluating various other aspects of hydraulic fracturing such as the potential environmental effects of hydraulic fracturing on drinking water and groundwater.

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, 2015, we (through our subsidiaries) employed approximately 1,432 full-time employees. Approximately 323 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 or results of operations 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 Energy Corporation for a substantial portion of the natural gas that we gather, process and transport. After the expiration of five-year minimum volume commitments from Devon at the end of 2018, a material decline in the volumes of natural gas that we gather, process and transport for Devon could result in a material decline in our operating results and cash available for distribution.

We are dependent on Devon for a substantial portion of our natural gas supply. For the year ended December 31, 2015, Devon represented 16.6% of our consolidated revenues. In order to minimize volumetric exposure, in March 2014 we obtained five-year minimum volume commitments from Devon at the Bridgeport processing facility, Bridgeport and East Johnson County gathering systems and the Cana system. After the expiration of these five-year minimum volume commitments in 2019, a material decline in the volume of natural gas that we gather and transport on our systems would result in a material decline in our combined total operating revenues and cash flow. In addition, Devon may determine in the future that drilling activity in areas of operation other than ours is strategically more attractive. A shift in Devon's focus away from our areas of operation could result in reduced throughput on our systems after the five-year minimum volume commitments expire and cause a material decline in our total operating revenues and cash flow. For the year ended December 31, 2015, we recognized $3.8 million under the minimum volume commitments attributable to our Texas Segment because volumes have been below the minimum level since August 2015. We also recognized $20.1 million under the minimum volume commitments attributable to our Oklahoma Segment because volumes have been below the minimum levels since June 2014. However, for the fourth quarter of 2015 volumes delivered to Cana exceeded minimum volume requirements.

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 substantial 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 the continuing deterioration of 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. On February 2, 2016, Standard & Poor's Rating Services ("S&P") downgraded Devon to a BBB credit rating. 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 1.A in Devon's Annual Report on Form 10-K for the year ended December 31, 2015 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 17.4% of our consolidated revenues for the year ended December 31, 2015. 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 and results of operations.

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

In order to maintain or increase throughput levels in our natural gas gathering systems and asset utilization rates at our processing plants and to fulfill our current sales commitments, 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, we have seen a decline in drilling activity due to low commodity prices. Although drilling activity has already slowed, if the current period of low commodity prices continues, we would expect additional downward pressure on future drilling activity, 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 depressed commodity prices or otherwise, likely would have a material adverse effect on our results of operations and financial position.

Any decrease in the volumes that we gather, process, fractionate or transport would adversely affect our financial condition, results of operations and 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 revenues and results of operations. 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 $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, primarily as a result of the further decline in commodity prices and the public trading price of our common units. We could experience future events that result in impairments. 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 not result in revenue increases and may be subject to regulatory, environmental, political, legal and economic risks, which could adversely affect our cash flows, results of operations and financial condition.

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 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 results of operations and financial condition. 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 business results of operation, liquidity and financial condition.

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 business, results of operations, liquidity and financial condition. 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 and internal financial controls. 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.

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

We cannot assure you that our credit ratings will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances so warrant. On February 2, 2016, S&P downgrade us to a BBB- credit rating, and our rating is currently under review by Moody's Investors Service. 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 results of operations, cash flows and financial condition.

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 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 on our NTPL 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, 2015 reflects a liability of $62.8 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, which 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, 2015, approximately 2.8% of our total gross operating margin was generated under percent of liquids contracts and percent of proceeds contracts. 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, 2015, approximately 0.7% 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 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, 2015, 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 2015. Crude oil, weighted average NGL, and natural gas prices declined 30%, 18% and 26%, respectively from January 1, 2015 to December 31, 2015. We expect this volatility to continue. For example, crude oil prices (based on the NYMEX futures daily close prices for the prompt month) in 2015 ranged from a high of $61.43 per Bbl in June 2015 to a low of $34.73 per Bbl in December 2015. Weighted average NGL prices in 2015 (based on the Oil Price Information Service (“OPIS”) Napoleonville daily average spot liquids prices) ranged from a high of $0.56 per gallon in March 2015 to a low of $0.37 per gallon in December 2015. Natural gas prices (based on Gas Daily Henry Hub closing prices) during 2015 ranged from a high of $3.23 per MMBtu in January 2015 to a low of $1.76 per MMBtu in December 2015.

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 security 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 at our intended levels.

Interest rates on future credit facilities and debt offerings could be higher than current levels, causing our financing costs to increase accordingly. As with other yield-oriented securities, 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.

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 results of operations and financial condition.

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 results of operations and financial condition.

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 acquired assets and markets 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 and compression facilities are located, which could disrupt our operations.

We do not own most of the land on which our pipelines and compression 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 operations and earnings.

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 claims arising from personal injury, property damage and environmental penalties and remediation.

We could experience increased severity or frequency of trucking accidents and other claims.

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, 2015, approximately 50.4% 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, end-users and utilities may be reluctant to enter into long-term purchase contracts. Many 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 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 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 and results of operations.

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, many of our customers' equity values have substantially declined. The combination of a reduction of cash flow resulting from declines in 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. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into the formation to stimulate gas production. Hydraulic fracturing typically is regulated by state oil and natural gas commissions. In addition, certain federal agencies have proposed additional laws and regulations to more closely regulate the hydraulic fracturing process. For example, in August 2015, the EPA proposed updates to new source performance standard requirements that would impose more stringent controls on methane, a GHG, and volatile organic compounds emissions from oil and gas development and production operations, including hydraulic fracturing and other well completion activity. Congress from time to time has considered the adoption of legislation to provide for federal regulation of hydraulic fracturing under the SDWA and to require disclosure of the chemicals used in the hydraulic fracturing process. Some states have adopted, and other states are considering adopting, legal requirements that could impose more stringent permitting, public disclosure or well construction requirements on hydraulic fracturing activities. Local governments have also adopted and may seek to adopt further ordinances regulating, within their jurisdictions, the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular, in some cases banning hydraulic fracturing entirely. For example, Oklahoma, Texas, and many other states have imposed regulations regarding disclosure of information regarding chemicals in well stimulation operations. Other governmental agencies, including the U.S. Department of Energy and the EPA, have evaluated or are evaluating various other aspects of hydraulic fracturing such as the potential environmental effects of hydraulic fracturing on drinking water and groundwater.

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 produced by fracking 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, and some state regulatory agencies have modified their regulations to account for induced seismicity. For example, the 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. 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. As regulatory agencies continue to study induced seismicity, such agencies may promulgate additional regulations, which could affect natural gas production by our customers and could directly affect 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 under Section 311 of the Natural Gas Policy Act 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” 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.

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 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. 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 liquids transportation pipelines in the ORV and the VEX and Cajun-Sibon pipeline are subject to regulation by FERC under the ICA, the Energy Policy Act of 1992 and the rules and regulations promulgated under those laws. The ICA and its implementing regulations require that tariff rates and terms and conditions of service for interstate service on liquids pipelines be just, reasonable and not unduly discriminatory or preferential. The ICA also requires that such rates and terms and conditions be set forth in tariffs filed with FERC. 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 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 ability to set rates based on our costs or could order us to reduce our rates and could require the payment of reparations to complaining shippers for up to two years prior to the 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, 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 states in which we conduct operations administer federal pipeline safety standards under the Natural Gas Pipeline Safety Act of 1968. These standards only apply to certain natural gas gathering lines based on the gathering line’s operating pressure and proximity to people. Because of their pressure and location, substantial portions of our gathering facilities are not regulated under that statute. The gathering line exemptions, however, may be revised in the future and place more of our gathering facilities under jurisdiction of the DOT. Nonetheless, our natural gas transmission pipelines are subject to regulation by the DOT. In response to pipeline accidents in other parts of the country, Congress and the DOT, through PHMSA, have passed or are considering heightened pipeline safety requirements that may be applicable to gathering lines. As a result, our pipeline facilities are subject to the Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011, which reauthorized funding for federal safety programs through 2015, 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.

At the state level, several states have passed legislation or promulgated rulemaking addressing pipeline safety. Compliance with these laws and rules 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, $2.5 million, and $7.0 million for the years ended December 31, 2015, 2014 and 2013, respectively. We expect the costs for compliance with TRRC and DOT regulations to be approximately $3.6 million during 2016. 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.

In addition, our liquids transportation pipelines are subject to regulation by the DOT, through PHMSA, pursuant to the Hazardous Liquids Pipeline Safety Act of 1979, as amended by the Pipeline Safety Improvement Act of 2002, and reauthorized and amended by the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006. PHMSA has adopted regulations requiring hazardous liquid pipeline operators to develop and implement integrity management programs for pipeline segments that, in the event of a leak or rupture, could affect “high consequence areas,” such as high population areas, areas that are sources of drinking water, ecological resource areas that are unusually sensitive to environmental damage from a pipeline release and commercially navigable waterways, unless the operator effectively demonstrates by risk assessment that the pipeline could not affect the area.

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. As our operations continue to expand into and 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 gathering systems, processing plants, fractionators, brine disposal operations and other facilities are subject to significant federal, state and local environmental laws and regulations. The obligations imposed by these laws and regulations include obligations related to air emissions and discharge of pollutants from our facilities and the cleanup of hazardous substances and other wastes that 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. Various governmental authorities have the power to enforce compliance with these laws and regulations and the permits issued under them, and violators are subject to administrative, civil and criminal penalties, including civil fines, injunctions or both. Strict, joint and several liability may be incurred under these laws and regulations 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 as well as to seek damages for non-compliance with environmental laws and regulations for releases of contaminants or for personal injury or property damage.

There is inherent risk of the incurrence of significant environmental costs and liabilities in our business due to our handling of natural gas, crude oil and other petroleum substances, our brine disposal operations, air emissions related to our operations, historical industry operations, waste disposal practices and the prior use of natural gas flow meters containing mercury. For example, we operate brine disposal wells in Ohio and West Virginia and may gather brine from surrounding states. These wells are regulated under the SDWA as Class II wells and under state laws. State laws and regulations that govern these operations can be more stringent than the SDWA, such as the Ohio Department of Natural Resources rules which in 2012, imposed new, more stringent environmentally responsible 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 regulates the transportation and disposal of brine. In addition, the possibility exists that stricter laws, regulations or enforcement policies could significantly increase our compliance costs and the cost of any remediation that may become necessary. We may incur material environmental costs and liabilities. Furthermore, our insurance may not provide sufficient coverage in the event an environmental claim is made against us.

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. 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.

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 relating to our operations, including our processing, storage or transportation activities, as well as, waste management or air emissions might adversely affect our business and our profitability. Federal and state agencies could also impose additional safety requirements, any of which could affect 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.

On April 17, 2012, the EPA approved final rules under the Clean Air Act that establish new air emission controls for oil and natural gas production, pipelines and processing operations. These rules became effective on October 15, 2012. Among other things, these rules require additional emissions controls for natural gas and NGLs production, including New Source Performance Standards to address emissions of sulfur dioxide and VOCs and a separate set of emission standards to address hazardous air pollutants frequently associated with such production activities. The final regulations require, among other things, the reduction of VOC emissions from natural gas wells through the use of reduced emission completions or “green completions” on all hydraulically fractured wells constructed or refractured after January 1, 2015. Moreover, these rules establish specific requirements regarding emissions from compressors and controllers at natural gas gathering and boosting stations and processing plants together with dehydrators and storage tanks at natural gas processing plants, compressor stations and gathering and boosting stations. The rules also establish new requirements for leak detection and repair of leaks at natural gas processing plants that exceed 500 parts per million in concentration. These rules required a number of modifications to our assets and operations and could require additional modifications both to our and to 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.

In addition, in August 2015, the EPA proposed updates to new source performance standard requirements that would impose more stringent controls on methane, a GHG, and volatile organic compounds emissions from oil and gas development and production operations, including hydraulic fracturing and other well completion activity. We cannot predict the costs of compliance with any modified or newly issued 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 will be open for signing on April 22, 2016 and will require 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. Following a finding by the EPA that certain GHGs represent an endangerment to human health, the EPA adopted two sets of rules regulating GHG emissions under the Clean Air Act, one that requires a reduction in emissions of GHGs from motor vehicles and another that regulates emissions of GHGs from certain large stationary sources. The EPA has also expanded its existing GHG emissions reporting requirements to include upstream petroleum and natural gas systems that emit 25,000 metric tons or more of CO_2 equivalent per year. These permitting and reporting requirements could lead to further regulation of GHGs by the EPA. Furthermore, in August 2015, the EPA proposed changes to its regulations imposing more stringent controls on methane, a GHG, and volatile organic compounds emissions from oil and gas development and production operations. A final rule is expected in 2016. The Administration has also announced that other federal agencies, including the Bureau of Land Management, the PHMSA, and the Department of Energy will impose new or more stringent regulations on the oil and gas sector that will have the effect of reducing methane emissions.

In addition, almost half of the 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.

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. Such a designation 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, 2015, 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.

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 adversely impact our 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 business, financial condition, results of operation or cash flows.

Our assets were constructed over many decades 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 business and results of operations.

Our pipelines were constructed over many decades. Pipelines are generally long-lived assets, and pipeline construction and coating techniques have varied over time. Depending on the era of construction, some assets will require more frequent inspections, which could result in increased maintenance or repair expenditures in the future. Any significant increase in these expenditures could adversely affect our results of operations, financial position or cash flows, as well as our ability to make cash distributions to our unitholders.

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 70.3% limited liability company interest as of December 31, 2015. 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 47.7% of all the outstanding units as of February 10, 2016.

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, 2015, ENLC and its affiliates, including Devon, owned 55.2% 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, 2015, ENLC and its affiliates, including our largest holder Devon, held an aggregate of183,189,051 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, 2015, only approximately 44.9% 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 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 equityholders, 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 Revised Uniform Limited Partnership Act, which we refer to herein as 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 1% of our gross income 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 and 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 and 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 to us to be treated as a partnership for federal income tax purposes.

On May 5, 2015, the U.S. Treasury Department and the IRS released proposed regulations (the "Proposed Regulations") regarding qualifying income under Section 7704(d)(1)(E) of the Code. The U.S. Treasury Department and the IRS have requested comments from industry participants regarding the standards set forth in the Proposed Regulations. The Proposed Regulations provide an exclusive list of industry-specific activities and certain limited support activities that generate qualifying income. We do not believe the Proposed Regulations affect our ability to qualify as a publicly-traded partnership. However, the Proposed Regulations could be changed before they are finalized and could take a position that is contrary to our interpretation. In the event that we do not satisfy the standards set forth in the final regulations for income that we treat as qualifying, we anticipate being able to continue to treat income from these activities as qualifying income for ten years under special transition rules provided in the Proposed Regulations.

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 material 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 disputed the denial and intend to proceed with litigation against 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 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.

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". Prior to March 10, 2014, our common units traded on the Nasdaq Global Select Market LLC under the symbol "XTEX." On February 10, 2016, there were approximately 33,043 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 New York Stock Exchange or the Nasdaq Global Select Market LLC, as applicable, and cash distributions declared per common unit for the periods indicated.

	Range		Cash Distribution Declared Per Unit
	High	Low	
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
2014:			
Quarter Ended December 31	$ 31.50	$ 25.42	$ 0.375
Quarter Ended September 30	32.08	28.15	0.370
Quarter Ended June 30	32.17	29.01	0.365
Quarter Ended March 31	35.10	26.91	0.360

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, less reserves that our general partner determines are necessary to:

- provide for the proper conduct of our business;
- comply with applicable law, any of our debt instruments or other agreements;
- provide funds for distributions to our unitholders and to our general partner for any one or more of the next four quarters; or
- plus all cash on hand for the quarter resulting from working capital borrowings made after the end of the quarter on the date of determination of available cash.

Under our existing credit facility, we may be limited from making certain distributions if an event of default exists. Please read "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operation—Indebtedness."

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.

Class C common units. The Class C common units will automatically convert into common units on a one-for-one basis on the first business day following the date of the distribution for the quarter ended March 31, 2016. Distributions on the Class C common units for the three months ended March 31, 2016 are expected to be paid-in-kind and all subsequent quarterly distributions will be paid in cash.

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 “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 the selected historical financial and operating data of the Partnership and the Predecessor for the periods indicated. Financial and operating data for the years ended December 31, 2014 and 2015 include such information for the following acquisitions for periods subsequent to the applicable acquisition date: certain assets acquired from Chevron in November 2014; January 2015 acquisition of LPC assets; March 2015 acquisition of Coronado assets; October 2015 acquisition of certain Matador assets; and November 2015 acquisition of remaining 50% interest in the Deadwood plant. The selected combined historical financial data of the Predecessor are derived from the historical combined financial statements of the Predecessor and should be read together with “Management’s Discussion and Analysis of Financial Condition and Results of Operations” below, including under the caption “Items Affecting the Comparability of our Financial Results,” and its audited combined financial statements for the periods ended, in order as of the dates indicated. The following information is only a summary and is not necessarily indicative of the results or future operations of the Partnership.

	EnLink Midstream Partners, LP Year Ended December 31,				
	2015	2014	2013	2012	2011
	(In millions, except per unit data)				
Statement of Operations Data:					
Revenues:					
Product sales	$ 3,253.7	$ 2,159.3	$ 179.4	$ 153.9	$ 13.6
Product sales- affiliates	119.4	505.6	2,116.5	1,753.9	2,514.4
Midstream services	451.0	253.4	—	—	—
Midstream services- affiliates	618.6	567.4	—	—	—
Gain on derivatives	9.4	22.1	—	—	—
Total revenue	4,452.1	3,507.8	2,295.9	1,907.8	2,528.0
Operating costs and expenses:					
Purchased gas, NGLs, condensate and crude oil (1)	3,245.3	2,494.5	1,736.3	1,428.1	1,974.9
Operating expenses (2)	419.9	283.6	156.2	149.9	137.1
General and administrative (3)	132.4	94.5	45.1	41.7	38.5
Depreciation and amortization	387.3	284.3	187.0	145.4	133.5
(Gain) loss on sale of property	1.2	(0.1)	—	—	—
Impairments	1,563.4	—	—	16.4	—
Gain on litigation settlement	—	(6.1)	—	—	—
Other expenses	—	—	—	—	(58.1)
Total operating costs and expenses	5,749.5	3,150.7	2,124.6	1,781.5	2,225.9
Operating income (loss)	(1,297.4)	357.1	171.3	126.3	302.1
Other income (expense):					
Interest expense, net of interest income	(102.5)	(47.4)	—	—	—
Income from unconsolidated affiliates	20.4	18.9	14.8	2.0	9.3
Gain on extinguishment of debt	—	3.2	—	—	—
Other income (expense)	0.8	(0.5)	—	—	—
Total other income (expense)	(81.3)	(25.8)	14.8	2.0	9.3
Income (loss) from continuing operations before non-controlling interest and income taxes	(1,378.7)	331.3	186.1	128.3	311.4
Income tax (provision) benefit	0.5	(22.0)	(67.0)	(46.2)	(112.1)
Net income (loss) from continuing operations	(1,378.2)	309.3	119.1	82.1	199.3
Discontinued operations:					
Income (loss) from discontinued operations, net of tax	—	1.0	(2.3)	(5.2)	18.9
Income from discontinued operations attributable to non-controlling interest, net of tax	—	—	(1.3)	(1.1)	(2.1)
Discontinued operations, net of tax	—	1.0	(3.6)	(6.3)	16.8
Net income (loss)	(1,378.2)	310.3	115.5	75.8	216.1
Less: Net loss from continuing operations attributable to the non-controlling interest	(0.4)	(0.2)	—	—	—
Net income (loss) attributable to EnLink Midstream Partners, LP	$ (1,377.8)	$ 310.5	$ 115.5	$ 75.8	$ 216.1
Predecessor interest in net income	$ —	$ 35.5	$ —	$ —	$ —
General partner interest in net income	$ 58.0	$ 138.3	$ —	$ —	$ —
Limited partners' interest in net income (loss) attributable to EnLink Midstream Partners, LP	$ (1,405.2)	$ 136.7	$ —	$ —	$ —
Class C Partner' interest in net income (loss) attributable to EnLink Midstream Partners, LP	$ (30.6)	$ —	$ —	$ —	$ —
Net income (loss) attributable to EnLink Midstream Partners, LP per limited partners' unit:					
Basic and diluted common unit	$ (4.66)	$ 0.59	$ —	$ —	$ —
Distributions declared per limited partner unit	$ 1.545	$ 1.47	$ —	$ —	$ —

(1) Includes $141.3 million, $354.3 million, $1,588.2 million, $1,310.3 million, and $1,762.6 million for the year ended December 31, 2015, 2014, 2013, 2012 and 2011, respectively, of affiliate purchased gas.

(2) Includes $0.5 million, $5.9 million, $36.2 million, $33.8 million, and $34.4 million for the year ended December 31, 2015, 2014, 2013, 2012 and 2011, respectively, of affiliate operating expenses from Devon.

(3) Includes $0.2 million, $11.6 million, $45.1 million, $41.7 million, and $38.5 million for the year ended December 31, 2015, 2014, 2013, 2012 and 2011, respectively, of affiliate general and administrative expenses from Devon.

	EnLink Midstream Partners, LP Year Ended December 31,				
	2015	2014	2013	2012	2011
	(In millions, except per unit data)				
Balance Sheet Data (end of period):					
Property and equipment, net	$ 5,666.8	$ 5,042.8	$ 1,768.1	$ 1,739.4	$ 1,550.7
Total assets	8,115.8	8,702.0	2,309.8	2,535.2	2,305.3
Long-term debt (including current maturities)	3,089.8	2,022.5	—	—	—
Partners' equity including non-controlling interest	4,434.5	6,025.9	1,783.7	2,002.0	1,901.2

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, impairment expense, unit-based compensation, (gain) loss on noncash derivatives, transaction costs, distribution of unconsolidated affiliate investment and non-controlling interest and income on unconsolidated affiliate investment. Adjusted EBITDA is used as a supplemental 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 from continuing operations, operating income (loss), cash flows from 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 both net earnings determined under GAAP, as well as adjusted EBITDA, to evaluate our overall performance.

The following tables reconcile adjusted EBITDA to the most directly comparable GAAP measure for the periods indicated.

Reconciliation of net income (loss) from continuing operations to adjusted EBITDA	**Year Ended December 31,**		
	2015	**2014**	**2013**
		(In millions)	
Net income (loss) from continuing operations	$ (1,378.2)	$ 309.3	$ 119.1
Interest expense	102.5	47.4	—
Depreciation and amortization	387.3	284.3	187.0
Impairments	1,563.4	—	—
(Gain) loss on sale of property	1.2	(0.1)	—
Income from unconsolidated affiliate investments	(20.4)	(18.9)	(14.8)
Gain on extinguishment of debt	—	(3.2)	—
Distribution from unconsolidated affiliate investments	42.7	23.7	12.0
Stock-based compensation	35.7	22.2	12.8
Income tax provision (benefit)	(0.5)	22.0	67.0
Payments under onerous performance obligation offset to other current and long-term liabilities	(17.9)	(14.7)	—
Other (1)	19.0	(18.4)	—
Adjusted EBITDA before non-controlling interest	$ 734.8	$ 653.6	$ 383.1
Non-controlling interest share of adjusted EBITDA	0.4	(0.2)	—
Transferred interest adjusted EBITDA (2)	(56.9)	(193.0)	—
Predecessor adjusted EBITDA (3)	—	(82.8)	(383.1)
Adjusted EBITDA	$ 678.3	$ 377.6	$ —

(1) Includes financial derivatives marked-to-market, accretion expense associated with asset retirement obligations, reimbursed costs from Devon and successful acquisition transaction costs.

(2) 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.

(3) 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 net cash provided by operating activities plus adjusted EBITDA, net to EnLink Midstream Partners, LP, less interest expense, litigation settlement adjustment, interest rate swap proceeds, cash taxes and other, maintenance capital expenditures and Predecessor adjusted EBITDA. Distributable cash flow is used as a supplemental performance 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, 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 flows from operating activities or any other measure of financial performance presented in accordance with GAAP. 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 both net earnings determined under GAAP, as well as distributable cash flow, to evaluate our overall performance.

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

	Year Ended December 31,		
	2015	2014	2013
	(in millions)		
Net cash provided by operating activities	$ 645.6	$ 479.4	$ 330.3
Interest expense, net (1)	104.0	48.6	—
Unit-based compensation (2)	—	2.8	12.8
Current income tax	3.1	6.7	31.5
Distributions from unconsolidated affiliate investment in excess of earnings	21.1	10.9	1.1
Other (3)	10.7	3.5	(0.4)
Changes in operating assets and liabilities which provided cash:			
Accounts receivable, accrued revenues, inventories and other	(201.6)	98.1	(0.8)
Accounts payable, accrued purchases and other (4)	151.9	3.6	8.6
Adjusted EBITDA before non-controlling interest	$ 734.8	$ 653.6	$ 383.1
Non-controlling interest share of adjusted EBITDA	0.4	(0.2)	—
Transferred interest adjusted EBITDA (5)	(56.9)	(193.0)	$ —
Predecessor adjusted EBITDA (6)	—	(82.8)	(383.1)
Adjusted EBITDA, net to EnLink Midstream Partners, LP	$ 678.3	$ 377.6	$ —
Interest expense	(102.5)	(46.3)	—
Non-cash adjustment for mandatorily redeemable non-controlling interest	(1.8)	—	—
Litigation settlement adjustment	—	(4.7)	—
Interest rate swap (7)	(3.6)	(3.6)	—
Cash taxes and other	(2.8)	(0.1)	—
Maintenance capital expenditures (8)	(38.3)	(21.5)	—
Distributable cash flow	$ 529.3	$ 301.4	$ —

(1) Net of amortization of debt issuance costs, discount and premium, and valuation adjustment for mandatorily redeemable non-controlling interest included in interest expense.

(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) Includes successful acquisition transaction costs and reimbursed employee costs from Devon and LPC.

(4) Net of payments under onerous performance obligation offset to other current and long-term liabilities.

(5) 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 as applicable.

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

(7) During the 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 therefore, excluded from distributable cash flow.

(8) Maintenance capital expenditures presented in our reconciliation to distributable cash flows above include only (i) our expenditures incurred at or after March 7, 2014 and (ii) our interest of the expenditures of Midstream Holdings 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, generally, 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 our business is generally 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. As an indicator of our operating performance, gross operating margin should not be considered an alternative to, or more meaningful than, net income as determined in accordance with GAAP. 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 gross operating margin to operating income (loss):

	Year Ended December 31,		
	2015	**2014**	**2013**
		(In millions)	
Total gross operating margin	$ 1,206.8	$ 1,013.3	$ 559.6
Add (deduct):			
Operating expenses	(419.9)	(283.6)	(156.2)
General and administrative expenses	(132.4)	(94.5)	(45.1)
Depreciation and amortization	(387.3)	(284.3)	(187.0)
Gain (loss) on sale of property	(1.2)	0.1	—
Gain on litigation settlement	—	6.1	—
Impairments	(1,563.4)	—	—
Operating income (loss)	$ (1,297.4)	$ 357.1	$ 171.3

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

You should 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, you should 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.

You should read this discussion in conjunction with the historical financial statements and accompanying notes included in this report. 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 Midstream Holdings.

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, condensate stabilization, brine services and marketing to producers of natural gas, NGLs, crude oil and condensate. Our midstream energy asset network includes approximately 9,400 miles of pipelines, 16 natural gas processing plants, seven fractionators, 3.2 million barrels of NGL cavern storage, 19.1 Bcf of natural gas storage, rail terminals, barge terminals, truck terminals and a fleet of approximately 150 trucks. We manage and report our activities primarily according to the nature of activity and geography. We have five reportable segments: (1) Texas, which includes our natural gas gathering, processing and transmission activities in north Texas and the Permian Basin in west Texas; (2) Oklahoma, which includes our natural gas gathering, processing and transmission activities in Cana-Woodford and Arkoma-Woodford Shale areas; (3) Louisiana, which includes our natural gas pipelines, natural gas processing plants and NGL assets located in Louisiana; (4) Crude and Condensate, which includes our Ohio River Valley ("ORV") crude oil, condensate and brine disposal activities in the Utica and Marcellus Shales, our equity interests in E2 Energy Services, LLC, E2 Appalachian Compression, LLC and E2 Ohio Compression, LLC (collectively, "E2"), 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 (5) Corporate, which includes our unconsolidated affiliate investments in Howard Energy Partners ("HEP") in the Eagle Ford Shale, 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 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 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" under "Item 6. Selected Financial Data." Approximately 96% of our gross operating margin (revenues less cost of sales) was derived from fee-based services with no direct commodity exposure for the year ended December 31, 2015. 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, processed at our processing facilities, the volumes of NGLs handled at our fractionation facilities, the volumes of crude oil and condensate handled at our crude terminals, the volumes of crude oil and condensate gathered, transported, purchased and sold, the volume of brine disposed and the volume of condensate stabilized. We generate revenues from seven primary sources:

- 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 transportation and terminal services;
- providing condensate stabilization services; and
- providing brine disposal services.

We typically gather or transport gas owned by others through our facilities for a fee. We also buy natural gas from a producer, plant or shipper at either a fixed discount to a market index or a percentage of the market index, 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 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 on our North Texas Pipeline 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 as a result of the March 7, 2014 business combination and was based on forecasted discounted cash obligations in excess of market prices under this gas delivery contract. As of December 31, 2015, the balance sheet reflects a liability of $62.8 million related to this performance obligation. 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.

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 generally 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, 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. Additionally, we provide crude oil, condensate and brine services on a volume basis.

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 decrease or increase significantly in the short term with decreases or increases 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 in its sole discretion.

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 Transferred Interests”) from Acacia, a wholly-owned subsidiary of ENLC, in a drop down transaction (the “February EMH Drop Down”). As consideration for the February 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 Transferred Interests” and, together with the February Transferred Interests, the “Transferred Interests”) from Acacia in a drop down transaction (the “May EMH Drop Down” and, together with the February EMH Drop Down, the “EMH Drop Downs”). As consideration for the May 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. See “Recent Growth Developments.”

Our units held by Devon represent approximately 28% of the outstanding limited partner interests in us, with approximately 45% of the outstanding limited partner interests held by our public unitholders and approximately 26% of the outstanding limited partner interests, the approximate 1% general partner interest and the incentive distribution rights held indirectly by ENLC as of December 31, 2015.

Recent Growth Developments

Acquisitions

Tall Oak. On January 7, 2016, we and ENLC acquired an 84% and 16% interest, respectively, in subsidiaries of Tall Oak Midstream, LLC (“Tall Oak”) for $1.55 billion, subject to certain adjustments (the “Tall Oak Acquisition”). The first installment of $1.05 billion for the acquisition was paid at closing and the final installment of $500.0 million is due no later than the first anniversary of the closing date with the option to defer $250.0 million of the final installment up to 24 months following the closing date.

The first installment consisted of approximately $1.05 billion and was funded by (a) approximately $788.0 million in cash contributed 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) (i) 15,564,009 common units representing limited liability company interests in ENLC issued directly by ENLC and (ii) approximately $19.5 million in cash contributed by ENLC.

Tall Oak's assets serve gathering and processing needs in the growing Sooner Trend Anadarko Basin Canadian and Kingfisher Counties (“STACK”) and Central Northern Oklahoma Woodford (“CNOW”) plays in Oklahoma and are supported by long-term, fixed-fee contracts with acreage dedications that have a remaining weighted-average term of approximately 15 years. Tall Oak’s 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 current capacity of 100 MMcf/d. Depending on future volume requirements, the Chisholm Plant could be expanded by an additional 600 MMcf/d for a total processing capacity of 700 MMcf/d. The plant is connected to a 200-mile, low and high-pressure gathering system with compression facilities. Additional gathering pipelines and compression facilities are currently under construction.

- *Battle Ridge Plant.* The Battle Ridge Plant, which provides us with an entry into the CNOW play, is a cryogenic gas processing plant with a current capacity of 75 MMcf/d. The plant is connected to a 175-mile, low and high-pressure gathering system with compression facilities. Additional gathering pipelines and compression facilities are currently under construction.

- *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 February 2016 and provides customers with additional operational flexibility.

Deadwood natural gas processing facility. On November 16, 2015, we acquired the remaining 50-percent ownership interest in the Deadwood natural gas processing facility from a subsidiary of Apache Corporation for approximately $40 million. The facility is located in Glasscock County, Texas in the Permian Basin. Pursuant to a 2011 agreement, we and Apache jointly funded the development of a new-build processing facility in which each company held a 50-percent undivided ownership interest. We managed the plant's initial construction and have operated the facility since its startup. The plant has a capacity of 58 MMcf/d and is currently processing approximately 61,500 MMBtu/d. The acquisition brings our net processing capacity in the Permian Basin to 343 MMcf/d.

Acquisition of Natural Gas Gathering and Processing Assets. On October 1, 2015, we acquired all of the voting interests in DLK Wolf Midstream, LLC, a subsidiary of MRC Energy Company ("Matador"), which owns natural gas gathering and processing assets located in west Texas (the "Delaware Basin System"), for $145.3 million, subject to certain adjustments. The Delaware Basin System consists of a cryogenic gas processing plant with approximately 35 MMcf/d of inlet capacity and approximately six miles of high-pressure gathering pipeline, which connects a low-pressure gathering system to the processing plant. Matador is the largest customer on the system and has dedicated approximately 11,000 gross acres currently under development pursuant to a 15-year fixed-fee gathering and processing agreement.

Coronado Midstream. On March 16, 2015, we acquired all of the voting equity interests in Coronado Midstream Holdings LLC, the parent company of Coronado Midstream LLC ("Coronado"), which owns natural gas gathering and processing facilities in the Permian Basin, for approximately $600.3 million in cash and equity, subject to certain adjustments. The purchase price consisted of $240.3 million in cash, 6,704,285 common units and 6,704,285 of our Class C common units. Coronado operates three cryogenic gas processing plants and a gas gathering system in the North Midland Basin including approximately 300 miles of gathering pipelines, 175 MMcf/d of processing capacity and 35,000 horsepower of compression. The Coronado system is underpinned by long-term contracts, which include the dedication of production from over 190,000 acres.

We acquired the Riptide plant located in the Permian Basin as part of the Coronado acquisition. The plant, which is under construction, will provide 100 MMcf/d of additional processing capacity and be tied to approximately 50 miles of new pipeline that is also under construction. The plant is expected to be completed in the first half of 2016.

LPC Crude Oil Marketing. On January 31, 2015, we acquired all of the voting interests in LPC Crude Oil Marketing LLC ("LPC"), which has crude oil gathering, transportation and marketing operations in the Permian Basin, for approximately $108.1 million. LPC is an integrated crude oil logistics service provider with operations throughout the Permian Basin. LPC's integrated logistics services are supported by 51 tractor trailers, 13 pipeline injection stations and 80 miles of crude oil gathering pipeline.

Organic Growth

HEP. During 2016, we plan to make contributions to HEP, primarily to fund our equity share of HEP's Nueva Era Pipeline. The Nueva Era Pipeline is a 50-50 joint venture between HEP and Mexico-based energy and services firm Grupo Clisa connecting HEP's existing Webb County Hub in South Texas directly to the Mexican National Pipeline System in Monterrey, Mexico. Mexico's Comisión Federal de Electricidad will be the foundation shipper on the approximately 200-mile, 30-inch Nueva Era Pipeline and will transport 504 MMcf/d on the system for a 25-year term.

Lobo II Natural Gas Gathering and Processing Facility. In the first quarter of 2016, we commenced construction of a new cryogenic gas processing plant and a gas gathering system in the Delaware Basin. The plant will initially provide 60 MMcf/d of processing capacity with a potential capacity of 120 MMcf/d and be tied to approximately 75 miles of new pipeline located in both in Texas and New Mexico that is also under construction. The plant and Texas portion of the pipeline are expected to be completed in the second half 2016 with the remaining New Mexico pipeline to be completed in the first quarter of 2017. The Lobo II system is supported by a long-term contract with an investment grade producer.

Ohio River Valley Condensate Stabilization Facilities. Through an agreement with Eclipse Resources, we constructed three natural gas compression and condensate stabilization facilities during late 2014 and 2015 in Harrison, Monroe and Guernsey counties in Ohio. We will begin construction on the fourth facility as needed based on available volumes.

Marathon Petroleum Joint Venture. We have entered into a series of agreements with a subsidiary of Marathon Petroleum Corporation ("Marathon Petroleum") to create a 50/50 joint venture named Ascension Pipeline Company, LLC. This joint venture will 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. This bolt-on project to our Cajun-Sibon NGL system is supported by long-term, fee-based contracts with Marathon Petroleum. Under the arrangement, we will serve as the construction manager and operator of the pipeline project, which is expected to be operational in the first half of 2017.

Drop Downs

Midstream Holdings Drop Down. In February and May, 2015, we acquired the Transferred Interests from Acacia, a wholly owned subsidiary of ENLC, through the consummation of the EMH Drop Downs. See "Devon Energy Transaction and EMH Drop Downs" above.

VEX Pipeline. On April 1, 2015, we acquired the Victoria Express Pipeline and related truck terminal and storage assets from Devon (the "VEX Interests"), 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. 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 at the destination of the pipeline include an eight-bay truck unloading terminal, 200,000 barrels of above-ground storage and rights to barge loading docks.

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, 2015 we sold an aggregate of 1.3 million common units under the BMO EDA, generating proceeds of approximately $24.4 million (net of approximately $0.3 million of commissions). We used the net proceeds for general partnership purposes. As of December 31, 2015, approximately $317.0 million remains available to be issued under the BMO EDA.

Private Placement of Common Units. 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, which we used for general partnership purposes.

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 $725.3 million after fees and deductions. Proceeds from the Private Placement were used to fund with the Tall Oak 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 will 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, 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.

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 purchased gas, NGLs, condensate and crude oil as reflected in the table below.

Items Affecting Comparability of Our Financial Results

Our historical financial results discussed below may not be comparable to our future financial results, and our historical financial results for the years ended December 31, 2013, 2014 and 2015 may not be comparable for the following reasons:

- 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.

- 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.
- Our financial statements for the years endedDecember 31, 2015 and 2014 report financial results according to operating segments based principally upon geographic regions served. The Predecessor had no operations for certain of those reporting segments.
- All historical affiliated transactions prior to March 7, 2014 related to our continuing operations were net settled within our combined financial statements because these transactions related to Devon and were funded by Devon's working capital. Beginning on March 7, 2014, all our transactions are funded by our working capital. This impacts the comparability of our cash flow statements, working capital analysis and liquidity discussion.
- The Predecessor's historical combined financial statements include U.S. federal and state income tax expense. Due to our status as a partnership, we are not be subject to U.S. federal income tax or certain state income taxes.

	Year Ended December 31,		
	2015	2014	2013
	(in millions, except volumes)		
Texas Segment			
Revenues	$ 1,000.2	$ 1,032.4	$ 1,549.1
Cost of sales	(412.2)	(456.9)	(1,130.4)
Total gross operating margin	$ 588.0	$ 575.5	$ 418.7
Louisiana Segment			
Revenues	$ 1,840.3	$ 1,837.4	$ —
Cost of sales	(1,567.6)	(1,674.2)	—
Total gross operating margin	$ 272.7	$ 163.2	$ —
Oklahoma Segment			
Revenues	$ 187.0	$ 318.8	$ 746.8
Cost of sales	(17.9)	(142.6)	(605.9)
Total gross operating margin	$ 169.1	$ 176.2	$ 140.9
Crude and Condensate Segment			
Revenues	$ 1,498.2	$ 367.2	$ —
Cost of sales	(1,330.6)	(290.9)	—
Total gross operating margin	$ 167.6	$ 76.3	$ —
Corporate			
Revenues	$ (73.6)	$ (48.0)	$ —
Cost of sales	83.0	70.1	—
Total gross operating margin	$ 9.4	$ 22.1	$ —
Total			
Revenues	$ 4,452.1	$ 3,507.8	$ 2,295.9
Cost of sales	(3,245.3)	(2,494.5)	(1,736.3)
Total gross operating margin	$ 1,206.8	$ 1,013.3	$ 559.6
Midstream Volumes:			
Texas (1)			
Gathering and Transportation (MMBtu/d)	2,849,600	2,958,000	2,102,000
Processing (MMBtu/d)	1,222,700	1,146,000	811,000
Louisiana (2)			
Gathering and Transportation (MMBtu/d)	1,468,300	615,200	—
Processing (MMBtu/d)	506,100	547,000	—
NGL Fractionation (Gals/d)	5,771,500	3,804,300	—
Oklahoma (3)			
Gathering and Transportation (MMBtu/d)	428,600	471,000	390,000
Processing (MMBtu/d)	359,600	442,000	400,000
Crude and Condensate (2)			
Crude Oil Handling (Bbls/d)	131,500	26,300	—
Brine Disposal (Bbls/d)	3,900	4,700	—

(1) Volumes include volumes per day based on 365 day period for the years ended December 31, 2015, 2014 and 2013 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, 2015, 2014 and 2013 respectively, for Midstream Holdings operations. We did not have any legacy operations in Oklahoma.

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 is 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 is attributable to the LPC, Coronado, Chevron, and Matador asset acquisitions, $13.0 million is attributable to the VEX pipeline, which commenced operations in July 2014, $21.6 million is attributable to our E2 assets due to the commercial start-up of five compression and condensate stabilization stations since the fourth quarter of 2014, and $51.5 million is 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. In addition, increases were further mitigated by a $11.9 million decrease in gross operating margin related primarily to volume declines in our Louisiana gas business. We also had $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 is attributable to legacy Partnership assets for a full year of operating expense during 2015 as compared to ten months during 2014, $59.0 million is attributable to direct operating costs of the LPC, Coronado, Matador and Chevron acquisitions during 2014 and 2015, $7.9 million is due to our Cajun-Sibon expansion completed in September 2014, $10.7 million is attributable to E2 compression and stabilization facilities that have been placed in service since the fourth quarter of 2014, $6.7 million is attributable to our Bearkat natural gas processing plant and rich gas gathering system which commenced operations in September 2014 and $5.2 million is 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 are as follows:

- $18.8 million is attributable to the legacy Partnership assets for a full year of expenses during 2015 as compared to ten months during 2014;
- $6.0 million is 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 Tall Oak, Matador, LPC and Coronado acquisitions, as well as the VEX dropdown;
- our unit-based compensation expense increased $3.2 million;
- our bad debt expense increased $2.3 million; and
- our salaries and wages increased $5.9 million 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 relates 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 is attributable to the legacy Partnership assets acquired in March 2014, $12.0 million is attributable to the Chevron acquisition in November 2014, $6.8 million is attributable to the LPC asset acquisition in January 2015, $25.6 million is attributable to the Coronado asset acquisition in March 2015 and $1.7 million is attributable to the Matador asset acquisition in October 2015. The remaining increase in depreciation and amortization expense of $35.1 million is 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 in our Crude and Condensate segment of $223.1 million during 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 capital projects. For more information, see the "Critical Accounting Policies" section 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 is 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 includes 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)
Mandatory 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. Of the increase in income from unconsolidated affiliate investments, $5.6 million is attributable to our investment in HEP due to acquisition activity that occurred in 2015. This increase is 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 as 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 relates to a reduction in our taxable income as compared to the Predecessor, which was a taxable entity prior to the business combination.

Year ended December 31, 2014 Compared to Year ended December 31, 2013

Gross Operating Margin. Gross operating margin was $1,013.3 million for the year ended December 31, 2014 compared to $559.6 million for the year ended December 31, 2013, an increase of $453.7 million, or 81.1%. Of this increase in gross operating margin, $386.8 million is attributable to the legacy Partnership assets associated with the business combination effective on March 7, 2014. Approximately $59.5 million of the increase in gross operating margin is related to an increase in gross operating margin at Midstream Holdings as a result of the new fixed-fee arrangements with Devon entered into in connection with the business combination and $7.4 million is attributable to the VEX pipeline which commenced operations in July 2014.

Operating Expenses. Operating expenses were $283.6 million for the year ended December 31, 2014 compared to $156.2 million for the year ended December 31, 2013, an increase of $127.4 million, or 81.6%. Of this increase in operating expenses, $145.6 million is attributable to the legacy Partnership assets and $5.4 million is attributable to VEX pipeline, partially offset by a decrease in Midstream Holdings' operating expenses of $23.6 million due to both lower personnel and contract labor expense and a decrease in compressor maintenance expense.

General and Administrative Expenses. General and administrative expenses were $94.5 million for the year ended December 31, 2014 compared to $45.1 million for the year ended December 31, 2013, an increase of $49.4 million, or 109.5%. General and administrative expenses for the year ended December 31, 2014 reflect expenses associated with the new combined operations of the legacy Partnership and Midstream Holdings since March 7, 2014, including $3.3 million for transition service costs from Devon, together with general and administrative expenses of Midstream Holdings prior to March 7, 2014. General and administrative expenses for the year ended December 31, 2013 reflect expenses for Midstream Holdings which primarily consisted of costs allocated by Devon for shared general and administrative services.

Depreciation and Amortization. Depreciation and amortization expenses were $284.3 million for the year ended December 31, 2014 compared to $187.0 million for the year ended December 31, 2013, an increase of $97.3 million, or 52.0%. The increase in depreciation and amortization expenses result from an increase in depreciation expense of $137.9 million related to the legacy Partnership assets acquired in March 2014 together with additional depreciation for net asset additions during 2014 and $4.0 million attributable to the VEX pipeline. These increases were partially offset by a decrease of $44.6

million in depreciation and amortization expenses related to Midstream Holdings primarily due to the change in depreciation methodology from the units-of-production method to the straight-line method which accounted for $29.4 million of such decrease. The remaining $5.6 million decrease was related to a change in the annual units-of-production rate partially offset by a $1.7 million increase related to assets placed in service during 2013.

Interest Expense. Interest expense was $47.4 million for the year ended December 31, 2014. There was no interest expense for the year ended December 31, 2013 as Midstream Holdings did not have any debt.

Income from Unconsolidated Affiliate Investments. Income from unconsolidated affiliate investments was $18.9 million for the year ended December 31, 2014 compared to $14.8 million for the year ended December 31, 2013. Of this increase in income from unconsolidated affiliate investments, $1.8 million is attributable to legacy Partnership unconsolidated affiliate investments. The remaining increase relates to our investment in GCF due to an improvement in turnaround downtime experience as compared to the 2013 period.

Income Tax Expense. Income tax expense was $22.0 million for the year ended December 31, 2014 as compared to income tax expense of $67.0 million for the year ended December 31, 2013, a decrease of $45.0 million. The decrease in income tax expense primarily relates to a reduction in our taxable income as compared to the Predecessor, which was a taxable entity prior to the business combination.

Net Income from Discontinued Operations. Net income from discontinued operations was $1.0 million for the year ended December 31, 2014 as compared to a net loss of $3.6 million for the year ended December 31, 2013, an increase of $4.6 million. The increase is due to Midstream Holdings' discontinued operations for the year ended December 31, 2013 which included assets that were sold during 2013, while year ended December 31, 2014 includes Predecessor assets that were not contributed to Midstream Holdings as part of 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 Note 2 of the Notes to Consolidated Financial Statements 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. FASB ASC 815 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 FASB ASC 360-10-05, 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 purchase and resale margins on natural gas, NGLs and crude oil, volume of gas, NGLs and crude oil available to the asset, markets available to the asset, operating expenses, and future natural gas, NGL product and crude oil prices. The amount of availability of gas, 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 and crude oil prices. Projections of gas, NGL and crude oil 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 2015, we reviewed our various assets groups for impairment due to the triggering events described in the goodwill impairment analysis below. 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. The non-cash impairment charge is included in the impairment expense line item of the Consolidated Statement of Operations. 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, during December 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.

Impairment of 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 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. During September 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.

We perform our goodwill assessments at the reporting unit level. 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 information, among other factors.

Using the fair value approaches described above, in step one of the goodwill impairment test, we determined that the estimated fair value of our Louisiana, Texas and Crude and Condensate reporting units were less than their carrying amounts, primarily due to changes in assumptions related to commodity prices, volume forecasts and discount rates. The second step of the goodwill impairment test measures the amount of impairment loss and involves allocating 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. Through the 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, which is included in impairment expense in the Consolidated Statements of Operations.

As of December 31, 2015, the goodwill allocated to our Louisiana reporting unit was fully impaired. We concluded that the fair value of goodwill of our Oklahoma reporting unit substantially exceeded its carrying value, and the entire amount of goodwill disclosed on the Consolidated Balance Sheet associated with the remaining reporting units is recoverable. However, the fair values of our Texas and Crude and Condensate reporting units were not substantially in excess of their carrying values. After considering the impairment losses above, the fair value of our Texas reporting unit exceeded its carrying value by 7.4 percent, and the fair value of our Crude and Condensate reporting unit approximates its carrying value. As of December 31, 2015, we had $703.5 million and $93.2 million of goodwill allocated to the Texas and Crude and Condensate reporting units, respectively.

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 for a reporting unit exceeds fair value. A continuing prolonged period of lower commodity prices may adversely affect our estimate of future operating results and our unit price, which could result in future goodwill impairment charges for our Texas and Crude and Condensate reporting units due to the potential impact on the cash flows of our operations. Due to further declines in both commodity prices and our unit price subsequent to December 31, 2015, it is likely that we will have a goodwill impairment in both our Texas and Crude and Condensate segments during the first quarter of 2016.

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.

Historically, Midstream Holdings depreciated certain property, plant, and equipment using the units-of-production method. As a result of the business combination, Midstream Holdings is operated as an independent midstream company and thus no longer has 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 minimum volume commitments. Effective March 7, 2014, the Partnership changed its method of computing depreciation for these assets to the straight-line method, consistent with the depreciation method applied to the Partnership's legacy assets. In accordance with FASB ASC 250, the Partnership determined that the change in depreciation method is a change in accounting estimate, and accordingly, the straight-line method will be applied on a prospective basis. This change is considered preferable because the straight-line method more accurately reflects the pattern of usage and the expected benefits of such 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, 2015, approximately 2.8% of our processed gas arrangements, 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 Coronado 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 processing gross operating margin under margin contracts. For the year ended December 31, 2015, approximately 0.7% of our processed gas arrangements, based on gross operating margin, was processed under margin contracts. We have a number of 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.

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

In the past, the prices of oil, natural gas and NGLs have been extremely volatile. Crude oil, weighted average NGL, and natural gas prices declined 30%, 18% and 26%, respectively from January 1, 2015 to December 31, 2015. We expect this volatility to continue. For example, crude oil prices (based on the NYMEX futures daily close prices for the prompt month) in 2015 ranged from a high of $61.43 per Bbl in June 2015 to a low of $34.73 per Bbl in December 2015. Weighted average NGL prices in 2015 (based on the Oil Price Information Service (“OPIS”) Napoleonville daily average spot liquids prices) ranged from a high of $0.56 per gallon in March 2015 to a low of $0.37 per gallon in December 2015. Natural gas prices (based on Gas Daily Henry Hub closing prices) during 2015 ranged from a high of $3.23 per MMBtu in January 2015 to a low of $1.76 per MMBtu in December 2015.

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 we gather and process. 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 $645.6 million, $479.4 million and $330.3 million for the years ended December 31, 2015, 2014 and 2013, respectively. Operating cash flows and changes in working capital for 2015, 2014 and 2013 were as follows (in millions):

	Year Ended December 31,		
	2015	**2014**	**2013**
Operating cash flows before working capital	$ 613.7	$ 590.0	$ 338.2
Changes in working capital	31.9	(110.6)	(7.9)
Total	$ 645.6	$ 479.4	$ 330.3

The primary reason for the increase in cash flows before working capital of $23.7 million from 2014 to 2015 relates to an increase in gross operating margin from the legacy Partnership assets acquired in March 2014, which are included for a full year in 2015 compared to ten months in 2014, and the assets acquired late in 2014 and during 2015 including the E2, Chevron, LPC, Coronado and VEX assets. Gross operating margin also increased due to start-up operations of organic growth projects. The change in working capital for 2015 and 2014 related to fluctuations in trade receivable and payable balances due to timing of collection and payments and changes in inventory balances due to normal operating fluctuations. The primary reason for the increase in cash flows before working capital of $251.8 million from 2013 to 2014 relates to an increase in gross operating margin from the legacy Partnership assets acquired in March 2014 and from the fixed-fee arrangements with Devon related to the Midstream Holdings assets. Further, prior to March 7, 2014, all cash receipts for the Predecessor were deposited into Devon’s bank accounts, and all cash disbursements were made from these accounts. Cash transactions handled by Devon were reflected in intercompany advances between Devon and the Predecessor, all of which were settled through an adjustment to equity and reflected in cash flows from financing activities. Subsequent to March 7, 2014, Midstream Holdings handles all of its cash transactions and the changes in working capital are reflected in our cash flows from operating activities.

Cash Flows from Investing Activities. Net cash used in investing activities was $1,097.3 million, $1,211.8 million and $243.2 million for the years ended December 31, 2015, 2014 and 2013, respectively. Our primary use of cash related to investing activities for the years ended December 31, 2015, 2014 and 2013 was acquisition costs and capital expenditures, net of accrued amounts, and an investment in unconsolidated affiliate investments as follows (in millions):

	Year Ended December 31,		
	2015	**2014**	**2013**
Growth capital expenditures	$ 530.0	$ 758.9	$ 180.8
Maintenance capital expenditures	42.3	37.1	63.5
Acquisition of business and asset purchases	524.2	421.1	—
Proceeds from sale of property	(1.0)	(0.1)	—
Proceeds from insurance settlement	(2.9)	—	—
Investment in unconsolidated affiliate investments	25.8	5.7	—
Distribution from unconsolidated affiliate investments in excess of earnings	(21.1)	(10.9)	(1.1)
Total	$ 1,097.3	$ 1,211.8	$ 243.2

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 is primarily attributable to a decrease in capital expenditures of $281.2 million related to our Cajun Sibon expansion project, which went into service in September 2014. This decrease is offset by an increase in capital expenditures of $46.7 million related to our E2 and ORV assets. Growth capital expenditures increased $578.1 million for the year ended December 31, 2014 as compared to the year ended December 31, 2013. The increase is primarily attributable to our Cajun Sibon expansion project and Bearkat natural gas processing facility both of which went into service in September 2014.

Maintenance capital expenditures increased $5.2 million for the year ended December 31, 2015 compared to the year ended December 31, 2014. The increase is primarily attributable to compressor overhauls and repairs in our Texas and Oklahoma segments. Maintenance capital expenditures decreased $26.4 million for the year ended December 31, 2014 compared to the year ended December 31, 2013. The decrease is primarily attributable to declines in well and trunkline connections in 2014 as compared to 2013 at our Bridgeport and Cana facilities in our Texas and Oklahoma segments.

Acquisition expenditures increased $103.1 million for the year ended December 31, 2015 as compared to the year ended December 31, 2014. Acquisitions of businesses during 2015 included the LPC, Coronado, Matador and Deadwood acquisitions. Acquisition of businesses during 2014 included the Chevron, E2 and VEX Interests. There were no acquisitions during 2013. See Note 3 - Acquisitions in the Notes to Consolidated Financial Statements under Part IV, Exhibit 15 of this Form 10-K.

Cash Flows from Financing Activities. Net cash provided by financing activities was $448.0 million and $742.0 million for the years ended December 31, 2015 and 2014, respectively, and net cash used in financing activities was $151.2 million for the year ended December 31, 2013. Our primary financing activities subsequent to March 7, 2014 consist of the following (in millions):

	Year Ended December 31,	
	2015	**2014**
Net borrowings (repayments) on bank credit facility	$ 176.8	$ (140.0)
Senior unsecured notes borrowings	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)
Net repayments under capital lease obligations	(3.6)	(3.0)
Debt refinancing costs	(9.5)	(18.5)
Proceeds from issuance of Partnership units	24.4	412.0
Proceeds from issuance of Partnership units to ENLC	50.0	—

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, 2015 and 2014 were as follows (in millions):

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

(1) Represents Midstream Holdings distributions to ENLC relating to ENLC's prior ownership interest in Midstream Holdings.

We received contributions from Devon of $27.8 million for year ended December 31, 2015 of which $2.2 million related to the reimbursement of employee costs and $25.6 million relates to funding of capital expenditures for the VEX assets. We received contributions of $105.7 million for the year ended December 31, 2014 which related to funding of capital expenditures for the VEX assets. Prior to the business combination, Midstream Holdings' continuing operations had no separate cash accounts. The owner contributions and distributions represent the net amount of all transactions that were settled with adjustments to equity. Midstream Holdings had distributions of $21.3 million to Devon for the year ended December 31, 2014 (relating to the period from January 1, 2014 to March 6, 2014) and distributions to Devon of $151.2 million for the year ended December 31, 2013.

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 revolving credit facility. We borrow money under our credit facility to fund checks as they are presented. As of December 31, 2015, we had approximately $1.1 billion of available borrowing capacity under this facility. Changes in drafts payable for 2015 were as follows (in millions):

	Year Ended December 31,		
	2015	2014	2013
Increase (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. 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 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.

Capital Requirements. 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, 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 and other gathering, well connections, compression and processing assets up to their original operating capacity, to maintain equipment reliability, integrity and safety and to address environmental laws and regulations.

We expect our 2016 capital expenditures, excluding Tall Oak acquisition of $1.55 billion and including capital contributions to our unconsolidated affiliate investments, to be as follows (in millions):

		2016
Growth Capital Expenditures		
Texas segment		$ 120 - 140
Louisiana segment		60 - 70
Oklahoma segment		150 - 180
Crude and Condensate segment		5 - 10
Corporate segment		80 - 140
Total		$ 415 - 540
Maintenance Capital Expenditures	$	35.0

Our primary capital projects for 2016 include completing the construction of our Riptide plant in our Texas segment, commencing construction of our Marathon joint venture NGL pipeline in our Louisiana segment, developing our Tall Oak assets in our Oklahoma segment and investing in HEP to fund our equity share of its pipeline expansion projects in our Corporate segment. See “Item 1. Business - Recent Growth Developments” for further details.

We expect to fund the growth capital expenditures from the proceeds of borrowing under our credit facility discussed below and proceeds from other debt and equity sources. We expect to fund our 2016 maintenance capital expenditures from operating cash flows. In 2016, 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, 2015, 2014 and 2013.

Total Contractual Cash Obligations. A summary of our total contractual cash obligations as ofDecember 31, 2015 is as follows (in millions):

	Payments Due by Period						
	Total	2016	2017	2018	2019	2020	Thereafter
Long-term debt obligations	$ 2,662.5	$ —	$ —	$ —	$ 400.0	$ —	$ 2,262.5
Credit facility	414.0	—	—	—	—	414.0	—
Other debt	0.2	0.1	0.1	—	—	—	—
Interest payable on fixed long-term debt obligations	1,843.3	120.0	120.0	120.0	114.6	109.2	1,259.5
Capital lease obligations	18.4	4.9	7.0	3.0	1.6	1.9	—
Operating lease obligations	126.9	11.7	9.0	13.9	11.0	8.6	72.7
Purchase obligations	52.8	52.8	—	—	—	—	—
Delivery contract obligation	62.7	17.9	17.9	17.9	9.0	—	—
Pipeline capacity and deficiency agreements (1)	25.2	7.6	7.0	7.3	3.3	—	—
Inactive easement commitment (2)	7.0	1.0	1.0	1.0	1.0	1.0	2.0
Uncertain tax position obligations	1.5	0.5	0.6	0.3	0.1	—	—
Total contractual obligations	$ 5,214.5	$ 216.5	$ 162.6	$ 163.4	$ 540.6	$ 534.7	$ 3,596.7

(1) Consists of pipeline capacity payments for firm transportation and deficiency agreements.

(2) Amounts related to inactive easements paid as utilized by us with balance due at end of 10 years if not utilized.

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, 2015, our cash obligation for interest expense on our credit facility would be approximately $7.5 million per year.

Indebtedness

As of December 31, 2015 and 2014, long-term debt consisted of the following (in millions):

	Year Ended December 31,	
	2015	2014
Partnership credit facility (due 2020), interest based on Prime and/or LIBOR plus an applicable margin, interest rate at December 31, 2015 and December 31, 2014 was 1.8% and 1.9%, respectively	$ 414.0	$ 237.0
Senior unsecured notes (due 2019), net of discount of $0.4 million at December 31, 2015 and $0.5 million at December 31, 2014, which bear interest at the rate of 2.70%	399.6	399.5
Senior unsecured notes (due 2022), including a premium of $18.9 million at December 31, 2015 and $21.9 million at December 31, 2014, which bear interest at the rate of 7.125%	181.4	184.4
Senior unsecured notes (due 2024), net of premium of $2.9 million at December 31, 2015 and $3.2 million at December 31, 2014, which bear interest at the rate of 4.40%	552.9	553.2
Senior unsecured notes (due 2025), net of discount of $1.2 million at December 31, 2015, which bear interest at the rate of 4.15%	748.8	—
Senior unsecured notes (due 2044), net of discount of $0.2 million at December 31, 2015 and $0.3 million at December 31, 2014, which bear interest at the rate of 5.60%	349.8	349.7
Senior unsecured notes (due 2045), net of discount of $6.9 million at December 31, 2015 and $1.7 million at December 31, 2014, which bear interest at the rate of 5.05%	443.1	298.3
Other debt	0.2	0.4
Debt classified as long-term	$ 3,089.8	$ 2,022.5

Credit Facility. On February 20, 2014, we entered into a new $1.0 billion unsecured revolving credit facility, which includes a $500.0 million letter of credit subfacility (the "Partnership credit facility"). On February 5, 2015, we exercised the accordion under the Partnership credit facility, increasing the size of the facility to $1.5 billion and also exercised an option to extend the maturity date of the Partnership credit facility to March 6, 2020. We also entered into certain amendments to the Partnership credit facility pursuant to which 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 the Partnership credit facility by an additional amount not to exceed $500 million and (2) subject to certain conditions and the consent of the requisite lenders, on two separate occasions extend the maturity date of the Partnership credit facility by one year on each occasion. The Partnership credit facility contains certain financial, operational and legal covenants. Among other things, these covenants include maintaining a ratio of consolidated indebtedness to consolidated EBITDA (as defined in the Partnership credit facility, which definition 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 the Partnership credit facility bear interest at our option at the Eurodollar Rate (the LIBOR Rate) plus an applicable margin 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. The applicable margins vary as shown in the table below depending on the Partnership's credit rating. On February 2, 2016, Standard and Poor's Rating Service ("S&P") downgraded us to a BBB- credit rating, and our rating is currently under review by Moody's Investors Service.

Pricing Levels	Debt Ratings	Applicable Rate Commitment Fee	EuroDollar Rate/Letter of Credit	Base Rate +
1	A-/A3 or better	0.100%	1.000%	—%
2	BBB+/Baa1	0.125%	1.125%	0.125%
3	BBB/Baa2	0.175%	1.250%	0.250%
4	BBB-/Baa3	0.225%	1.500%	0.500%
5	BB+/Ba1	0.275%	1.625%	0.625%
6	BB/Ba2 or worse	0.350%	1.750%	0.750%

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

As of December 31, 2015, there were $10.9 million in outstanding letters of credit and $414.0 million in outstanding borrowings under the Partnership credit facility, leaving approximately $1.1 billion available for future borrowing based on the borrowing capacity of $1.5 billion.

Senior Unsecured Notes. On March 7, 2014, we recorded $725.0 million in aggregate principal amount of 8.875% senior unsecured notes (the "2018 Notes") due on February 15, 2018 in the business combination. As a result of the business combination, the 2018 Notes were recorded at fair value in accordance with acquisition accounting at an amount of $761.3 million, including a premium of $36.3 million, as of March 7, 2014.

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 partial redemption of the 2022 Notes of $2.4 million for the year ended December 31, 2014.

On March 12, 2014, we commenced a tender offer to purchase any and all of the outstanding 2018 Notes. Approximately $536.1 million, or approximately 74%, of the 2018 Notes were validly tendered and on March 19, 2014, we made a payment of approximately $567.4 million for all such tendered 2018 Notes. Also on March 19, 2014, we delivered a notice of redemption for any and all outstanding 2018 Notes. All remaining outstanding 2018 Notes were redeemed on April 18, 2014 for $200.2 million, including accrued interest. We recorded a gain on extinguishment of debt related to the redemption of the 2018 Notes of $0.7 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 its 2.700% senior notes due 2019 (the "2019 Notes"), $450.0 million aggregate principal amount of its 4.400% senior notes due 2024 (the "2024 Notes") and $350.0 million aggregate principal amount of its 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 its 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.

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 of: (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 a part of the 2025 Notes 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 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.

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 2013, 2014 and 2015. 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 the 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 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 disputed the denial and intend to proceed with litigation against 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 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.

Recent Accounting Pronouncements

See *Note 2-Significant Accounting Policies* in the *Notes to Consolidated Financial Statements* under Item 15 of this Form 10-K.

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, 2015. During March 2015, we acquired processing plants from Coronado which generate gross operating margins based on percent of proceeds contracts.

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, 2015 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 *	Fair Value Asset/(Liability) (In millions)	
January 2016 - December 2016	Ethane	571	(MBbls)	$0.2903/gal	Index	$	(2.7)
January 2016 - December 2016	Propane	812	(MBbls)	Index	$0.8130/gal		13.9
January 2016 - December 2016	Normal Butane	113	(MBbls)	Index	$0.6122/gal		0.3
January 2016 - December 2016	Natural Gasoline	61	(MBbls)	Index	$1.0231/gal		0.3
January 2016 - January 2017	Natural Gas	13,829	(MMBtu/d)	$2.6533/MMBtu*	Index		1.8
January 2016	Condensate	0.1	(MBbls)	$42.2824/bbl*	Index		0.2
						$	13.8

* 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, 2015, outstanding natural gas swap agreements, NGL swap agreements, swing swap agreements, storage swap agreements and other derivative instruments were a net fair value asset of $13.8 million. The aggregate effect of a hypothetical 10% change, increase or decrease, in gas and NGL prices would result in a change of approximately $2.4 million in the net fair value of these contracts as of December 31, 2015.

Interest Rate Risk

We are exposed to interest rate risk on our variable rate bank credit facility. At December 31, 2015, we had $414.0 million in outstanding borrowings under this facility. A 1% increase or decrease in interest rates would change our annual interest expense by approximately $4.1 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, 2044, or 2045 as these are fixed rate obligations. The estimated fair value of our senior unsecured notes was approximately $2,171.3 million as of December 31, 2015, based on market prices of similar debt at December 31, 2015. 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 approximately a $191.4 million decrease in fair value of our senior unsecured notes at December 31, 2015.

Item 8. ***Financial Statements and Supplementary Data***

The Report of Independent Registered Public Accounting Firm, Consolidated Financial Statements and supplementary financial data required by this Item are set forth on pages F-1 through F-47 of this Report and are incorporated herein by reference.

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, 2015), 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, 2015 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Internal Control Over Financial Reporting

See “Management's Report on Internal Control over Financial Reporting” on page F-2.

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	54	President, Chief Executive Officer and Director
Michael J. Garberding	47	Executive Vice President and Chief Financial Officer
Steve J. Hoppe	53	Executive Vice President and President of Gas Gathering, Processing and Transmission
McMillan (Mac) Hummel	53	Executive Vice President and President of Natural Gas Liquids and Crude
Alaina Brooks	41	Senior Vice President, General Counsel and Secretary
Benjamin D. Lamb	36	Senior Vice President, Finance and Corporate Development
John Richels	64	Chairman of the Board
Thomas L. Mitchell	55	Director
David A. Hager	59	Director and Member of the Governance and Compensation Committee
Darryl G. Smette	68	Director
Mary P. Ricciardello**	60	Director and Member of the Audit Committee
Scott A. Griffiths**	61	Director and Member of the Compensation* and Conflicts Committees
Leldon E. Echols**	60	Director and Member of the Audit Committee*
Kyle D. Vann**	68	Director and Member of the Conflicts* and Audit Committees
Tony Vaughn	58	Director
Christopher Ortega	40	Director

* Denotes chairman of committee.

** Denotes independent director.

Barry E. Davis, President, Chief Executive Officer and Director, 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 a director.

Michael J. Garberding, Executive Vice President and Chief Financial Officer, joined our general partner in February 2008. Mr. Garberding assumed the role of Senior Vice President and Chief Financial Officer in August 2011 and the role of Executive Vice President and Chief Financial Officer in January 2013. Mr. Garberding previously led the finance and business development organization for the Partnership. Mr. Garberding has 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 our 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 and the Association of Oil Pipe Lines Pipeline Subcommittee. Mr. Hummel earned a Bachelor of Science degree in accounting and a Masters of Business Administration from the University of Utah.

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 company's 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.

Benjamin D. Lamb, Senior Vice President, Finance and Corporate Development, joined our general partner in December 2012. Mr. Lamb assumed his current role in November 2014, having previously served as Vice President - Finance. 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.

John Richels previously served as President and Chief Executive Officer of Devon from July 2010 until retiring effective on July 31, 2015. From January 2004 to June 2010, Mr. Richels served as President of Devon. He joined the Board of Directors of Devon in 2007. Prior to 2004, Mr. Richels served as a Senior Vice President of Devon and President and Chief Executive Officer of Devon's Canadian subsidiary. Mr. Richels joined Devon through its 1998 acquisition of Canadian-based Northstar Energy Corp. Prior to joining Northstar, Mr. Richels was Managing and Chief Operating Partner of the Canadian-based national law firm, Bennett Jones. Mr. Richels has served as a director of the general partner and the managing member of EnLink Midstream since the completion of the business combination on March 7, 2014. Mr. Richels also currently serves on the Boards of Devon, TransCanada Corp. and BOK Financial Corporation. He holds a Bachelor of Arts degree in Economics from York University and a law degree from the University of Windsor. Mr. Richels was appointed to the Board due to his extensive knowledge of the industry, including his experience with Midstream Holdings' assets and operations.

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.

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.

Darryl G. Smette has been the Executive Vice President Marketing, Facilities, Pipelines and Supply Chain of Devon since 1999. Prior to joining Devon, he spent 15 years in various marketing roles with Energy Reserves Group Inc. / BHP Petroleum (Americas) Inc. He is involved with the University of Texas Department of Continuing Education as an oil and gas industry instructor. Mr. Smette is also a member of the Oklahoma Independent Producers Association, Natural Gas Association of Oklahoma and the American Gas Association. Mr. Smette 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 serving as a director on the Board of Panhandle Oil & Gas Inc. and holds a Bachelor degree from Minot State University and a Masters in Business Administration degree from Wichita State University. Mr. Smette 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 also is a director on the Board of Energy XXI Ltd. and served as a director on the Board of EPL Oil and Gas Inc. until it was acquired by Energy XXI in 2014. Mr. Griffiths also served as a director on the Board of Copano Energy, LLC until it was acquired by Kinder Morgan Energy Partners in 2013. 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 our general partner 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., Eco Services 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.

Tony Vaughn joined our general partner as a director in January 2016. Mr. Vaughn is 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 recently as 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.

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. Our Board annually reviews the composition of the Board as a whole, which assessment includes the qualifications under applicable independence standards and other standards applicable to the Board and its committees, as well as consideration of skills and experience in the context of the needs of the Board.

Messrs. Echols, Vann, Griffiths and Ms. Ricciardello qualify as "independent" in accordance with the published listing requirements of the NYSE. The NYSE independence definition includes a series of objective tests, such as that the director is not an employee of our general partner and has not engaged in various types of business dealings with our general partner. In addition, as further required by the NYSE rules, our Board has made a subjective determination as to each independent director that no relationships exist that, in the opinion of the Board, would interfere with the exercise of independent judgment in carrying out the responsibilities of a director.

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 twelve times in 2015. 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 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 2015, 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. Due to administrative errors, a Form 3 was filed late as follows: on behalf of Acacia on April 1, 2015, regarding an acquisition of Class D common units on February 17, 2015. Due to administrative errors, Forms 4 were filed late as follows: on behalf of EMI on April 1, 2015, regarding an acquisition of common units on October 22, 2014; on behalf of ENLC, LLC on April 1, 2015, regarding an acquisition of common units on October 22, 2014 and an acquisition of Class D common units on February 17, 2015; on behalf of the Managing Member, on April 1, 2015, regarding an acquisition of common units on October 22, 2014 and an acquisition of Class D common units on February 17, 2015; on behalf of Devon Gas Services, L.P. on April 1, 2015, regarding a conversion of Class B common units into common units on May 6, 2014, an acquisition of common units on October 22, 2014 and an acquisition of Class D common units on February 17, 2015; on behalf of Devon, on April 1, 2015, regarding a conversion of Class B common units into common units on May 6, 2014, an acquisition of common units on October 22, 2014 and an acquisition of Class D common units on February 17, 2015; and on behalf of Southwestern Gas , on April 1, 2015, regarding a conversion of Class B common units into common units on May 6, 2014.

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 2015:

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%
Steve J. Hoppe	90%	10%
Mac Hummel	90%	10%
Michael J. Garberding	60%	40%
Ben 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, in the top quartile relative to 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 2015. Meridian's work for the Compensation Committee did not raise any conflicts of interest in 2015.

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., MarkWest Energy 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 the Company.

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 2015, 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 2015 (and payable for fiscal 2016) are as follows:

	Prior Salary	Base Salary Effective January 1, 2016	Percent Increase
Barry E. Davis	$ 660,000	$ 660,000	—%
Steve J. Hoppe	390,000	390,000	—%
Mac Hummel	390,000	390,000	—%
Michael J. Garberding	450,000	450,000	—%
Benjamin D. Lamb	280,000	310,000	10.7%

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 the overall Company's achievement level of EBITDA (see Item 6. "Selected Financial Data" 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 2015. Accordingly, the Compensation Committee and the Board awarded bonuses to the named executive officers as follows:

	Target Bonus Percentage (as a % of Base Salary)	**2015 Bonus (as a % of Base Salary)**	**2015 Bonus Amount**
Barry E. Davis	125 %	105 %	690,000
Steve J. Hoppe	90 %	77 %	300,000
Mac Hummel	90 %	77 %	300,000
Michael J. Garberding	90 %	89 %	400,000
Benjamin D. Lamb	60 %	80 %	225,000

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 2015, our adjusted EBITDA levels for bonuses were $692.0 million for minimum bonuses, $744.1 million for target bonuses and $818.5 million for maximum bonuses. For 2015, the STI Program provided for named executive officers to receive bonus payouts of 30% to 62.5% of base salary at the minimum threshold, 60% to 125% of base salary at the target level and 120% 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) in the upper quartile 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. Of the 9,070,000 common units that may be awarded under the GP Plan, 2,382,017 common units remain eligible for future grants as of December 31, 2015. 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 the tenth anniversary of the date of the GP Plan's most recent approval by unitholders of the Partnership, which was on May 9, 2013. 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, the total number of common units outstanding will increase, and 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. If we issue new common units upon vesting of the restricted incentive units, the total number of common units outstanding will increase. 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”) has 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, 9,826,736 common units remain eligible for future grants as of December 31, 2015. 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 the tenth anniversary of its effective date. 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.* 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.* 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.* 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.* 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.

- *Distribution Equivalent Rights or DERs.* DERs entitle a participant to receive cash or additional awards equal to the amount of any cash distributions made by us 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 Compensation Committee.

- *Unit Awards.* The 2014 Plan 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 permits the grant of cash awards, which are awards denominated and payable in cash.

- *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 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, 2015, 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 March 2015, 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 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 2015. In addition, our executive officers may receive additional grants of equity compensation in certain circumstances, such as promotions. For fiscal year 2015, our general partner granted 76,280, 34,577, 34,577, 44,389 and 34,951 performance and restricted incentive units to Barry E. Davis, Steve J. Hoppe, Mac Hummel, Michael J. Garberding and Ben Lamb, respectively. In addition, for fiscal year 2015, the managing member of EnLink Midstream granted 67,271, 30,518, 30,518, 39,078 and 29,384 performance and restricted incentive units to Barry E. Davis, Steve J. Hoppe, Mac Hummel, Michael J. Garberding and Ben Lamb, respectively. All performance and restricted incentive units that we grant are charged against earnings according to FASB Accounting Standards Codification 718- “Compensation-Stock Compensation” (FASB 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 2015, the Operating Partnership matched 100% of every dollar contributed for contributions of up to 6% 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 than Mr. Lamb and other members of senior management who 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, Mr. Lamb will be entitled to one 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 many 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, 2015 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 FASB 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 FASB ASC 718 under the fair value method and expense those amounts in the income statement over the unit option's remaining vesting period. As a result, we have discontinue 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. In 2015, Barry E. Davis had non-performance based compensation paid in excess of the $1.0 million tax deduction limit contained in Section 162(m) of the Internal Revenue Code.

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 Unit and Restricted Incentive 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	2015	659,308	690,000	3,435,500	—	—	—	440,742	(4)	5,225,550
President and Chief Executive	2014	587,885	800,000	6,000,000	—	1,600,000	—	683,607		9,671,492
Officer	2013	525,000	492,188	1,609,522	—	—	—	266,774		2,893,484
Steve J. Hoppe	2015	389,827	300,000	1,570,488	—	—	—	147,699	(5)	2,408,014
Executive Vice President and President of Gathering	2014	304,327	350,000	2,500,000	—	—	—	93,832		3,248,159
McMillan ("Mac") Hummel	2015	389,538	300,000	1,570,488	—	—	—	203,570	(6)	2,463,596
Executive Vice President and President of NGL and Crude	2014	325,569	350,000	2,131,596	—	—	—	84,625		2,891,790
Michael J. Garberding	2015	449,423	400,000	1,963,183	—	—	—	281,294	(7)	3,093,900
Executive Vice President and Chief Financial Officer	2014	391,923	500,000	3,000,000	—	800,000	—	480,884		5,172,807
	2013	350,000	224,100	1,465,519	—	—	—	164,596		2,204,215
Benjamin D. Lamb (9)	2015	283,904	225,000	1,702,321	—	—	—	92,414	(8)	2,303,639
Senior Vice President										

(1) Bonuses include all annual bonus payments. For 2015, all annual bonus payments will be paid in cash. For 2014 and 2013, the named executive officers received bonuses in the form of equity awards that immediately vest. The amounts shown for 2014 and 2013 represent the grant date fair value of awards computed in accordance with FASB 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 FASB ASC 718. See Note 9 to our audited financial statements included in Item 8 herein 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) profit sharing contribution of $6,413, a 401(k) non-discretionary contribution of $5,300, distributions on restricted units or restricted incentive units and performance units of EnLink Midstream Partners, LP in the amount of $260,108 in 2015 and distributions on restricted units or restricted incentive units and performance awards of EnLink Midstream, LLC in the amount of $153,021 in 2015.

(5) Amount of all other compensation for Mr. Steve Hoppe includes professional organization and social club dues, a matching 401(k) contribution of $15,900, a 401(k) profit sharing contribution of $6,413, a 401(k) non-discretionary contribution of $5,300, distributions on restricted incentive units and performance units of EnLink Midstream Partners, LP in the amount of $76,952 in 2015 and distributions on restricted incentive units and performance awards of EnLink Midstream, LLC in the amount of $43,134 in 2015.

(6) Amount of all other compensation for Mr. Mac Hummel includes professional organization and social club dues, a matching 401(k) contribution of $15,900, a 401(k) profit sharing contribution of $6,413, a 401(k) non-discretionary contribution of $5,300, moving costs of $68,323, distributions on restricted incentive units and performance units of EnLink Midstream Partners, LP in the amount of $71,228 in 2015, and distributions on restricted incentive units and performance awards of EnLink Midstream, LLC in the amount of $36,406 in 2015.

(7) Amount of all other compensation for Mr. Michael Garberding includes professional organization and social club dues, a matching 401(k) contribution of $15,542, a 401(k) profit sharing contribution of $6,413, a 401(k) non-discretionary contribution of $5,300, distributions on restricted units or restricted incentive units of EnLink Midstream Partners, LP in the amount of $158,809 in 2015 and distributions on restricted units or restricted incentive units of EnLink Midstream, LLC in the amount of $95,230 in 2015.

(8) Amount of all other compensation for Mr. Ben Lamb includes a matching 401(k) contribution of $15,484, a 401(k) profit sharing contribution of $6,413, a 401(k) non-discretionary contribution of $5,300, distributions on restricted units or restricted incentive units of EnLink Midstream Partners, LP in the amount of $42,590 in 2015, and dividends or distributions on restricted units or restricted incentive units of EnLink Midstream, LLC in the amount of $22,627 in 2015.

(9) Mr. Lamb became a named executive officer in fiscal year 2015, and, therefore, summary compensation information is presented only for fiscal year 2015.

Grants of Plan-Based Awards for Fiscal Year 2015 Table

The following tables provide information concerning each grant of an award made to a named executive officer for fiscal year 2015, 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 (1)			All Other Unit Awards: Number of Units		Grant Date Fair Value of Unit Awards
		Threshold (#)	Target (#)	Maximum(#)			
Barry E. Davis	3/3/2015				14,920	(1)	$ 400,005
	3/17/2015				30,680	(2)	$ 874,994
	3/17/2015	—	30,680	61,360			$ 812,713
Steve J. Hoppe	3/3/2015				6,527	(1)	$ 174,989
	3/17/2015				14,025	(2)	$ 399,993
	3/17/2015	—	14,025	28,050			$ 371,522
Mac Hummel	3/3/2015				6,527	(1)	$ 174,989
	3/17/2015				14,025		$ 399,993
	3/17/2015	—	14,025	28,050			$ 371,522
Michael J. Garberding	3/3/2015				9,325	(1)	$ 250,003
	3/17/2015				17,532	(2)	$ 500,013
	3/17/2015	—	17,532	35,064			$ 464,423
Benjamin D. Lamb	1/12/2015				3,439	(3)	$ 100,006
	3/5/2015				3,264	(1)	$ 87,508
	3/17/2015				11,695	(2)	$ 312,490
	3/17/2015	—	11,695	23,390			$ 309,801
	5/1/2015				4,858	(4)	$ 124,996

(1) These grants vested on March 3, 2015.

(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, 2018.

(3) These grants vested on January 12, 2015.

(4) 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 April 1, 2018.

ENLINK MIDSTREAM, 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 Shares Awards
	3/3/2015				11,891	(1)	$ 400,013
Barry E. Davis	3/17/2015				27,690	(2)	$ 875,004
	3/17/2015	—	27,690	55,380			$ 872,789
Steve J. Hoppe	3/3/2015				5,202	(1)	$ 174,995
	3/17/2015				12,658	(2)	$ 399,993
	3/17/2015	—	12,658	25,316			$ 398,980
Mac Hummel	3/3/2015				5,202	(1)	$ 174,995
	3/17/2015				12,658		$ 399,993
	3/17/2015	—	12,658	25,316			$ 398,980
	3/3/2015				7,432	(1)	$ 250,012
Michael J. Garberding	3/17/2015				15,823	(2)	$ 500,007
	3/17/2015	—	15,823	31,646			$ 498,741
	1/12/2015				3,079	(3)	$ 100,006
	3/5/2015				2,601	(1)	$ 87,498
Benjamin D. Lamb	3/17/2015				10,074	(2)	$ 312,495
	3/17/2015	—	10,074	20,148			$ 317,532
	5/1/2015				3,556	(4)	$ 124,993

(1) These grants vested on March 3, 2015.

(2) These grants include DERs that provide for distribution on restricted or restricted incentive units if made on unrestricted common units during the restriction period unless otherwise forfeited and vest 100% on January 1, 2018.

(3) These grants vested on January 12, 2015.

(4) These grants include DERs that provide for distribution on restricted or restricted incentive units if made on unrestricted common units during the restriction period unless otherwise forfeited and vest 100% on April 1, 2018.

Outstanding Equity Awards at Fiscal Year-End Table for Fiscal Year 2015

The following tables provide information concerning all outstanding equity awards made to a named executive officer as of December 31, 2015, 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 (#) Unexercisable	Equity Incentive Plan Awards: Number of Securities Underlying Unexercised Unearned Options (#)	Option Exercise Price ($)	Option Expiration Date	Number of Units That Have Not Vested (#)		Market Value of Units That Have Not Vested ($)(2)	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	—	—	—	—	—	51,546	(1)	854,633	30,680	(8)	508,674
						95,299	(4)	1,580,057			
						30,680	(6)	508,674			
Steve J. Hoppe	—	—	—	—	—	39,708	(4)	658,359	14,025	(8)	232,535
						14,025	(6)	232,535			
Mac Hummel	—	—	—	—	—	31,766	(4)	526,680	14,025	(8)	232,535
						4,201	(4)	69,653			
						14,025	(6)	232,535			
Michael J. Garberding	—	—	—	—	—	30,928	(1)	512,786	17,532	(8)	290,681
						11,985	(3)	198,711			
						47,649	(4)	790,020			
						17,532	(6)	290,681			
Benjamin D. Lamb	—	—	—	—	—	7,147	(4)	118,497	11,695	(8)	193,903
						8,194	(5)	135,857			
						11,695	(6)	193,903			
						4,858	(7)	80,546			

(1) Restricted incentive units vested on January 1, 2016.

(2) The closing price for the common units was $16.58 as of December 31, 2015.

(3) Restricted incentive units vest on July 31, 2016.

(4) Restricted incentive units vest on March 7, 2017.

(5) Restricted incentive units vest on July 23, 2017.

(6) Restricted incentive units vest on January 1, 2018.

(7) Restricted incentive units vest on April 1, 2018.

(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%, which in accordance with SEC rules is the next higher performance level under the award that exceeds 2015 performance. Vesting of these awards 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 (#) Unexercisable	Equity Incentive Plan Awards: Number of Securities Underlying Unexercised Unearned Options (#)	Option Exercise Price ($)	Option Expiration Date	Number Units That Have Not Vested (#)		Market Value of Shares or Units That Have Not Vested ($)(2)	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	—	—	—	—	—	52,301	(1)	789,222	27,690	(8)	417,842
						81,967	(4)	1,236,882			
						27,690	(6)	417,842			
Steve J. Hoppe	—	—	—	—	—	34,153	(4)	515,369	12,658	(8)	191,009
						12,658	(6)	191,009			
Mac Hummel	—	—	—	—	—	27,322	(4)	412,289	12,658	(8)	191,009
						12,658	(6)	191,009			
Michael J. Garberding	—	—	—	—	—	31,381	(1)	473,539	15,823	(8)	238,769
						12,267	(3)	185,109			
						40,984	(4)	618,449			
						15,823	(6)	238,769			
Benjamin D. Lamb	—	—	—	—	—	6,148	(4)	92,773	10,074	(8)	152,017
						6,445	(5)	97,255			
						10,074	(6)	152,017			
						3,556	(7)	53,660			

(1) Restricted incentive units vested on January 1, 2016.

(2) The closing price for the common units was $15.09 as of December 31, 2015.

(3) Restricted incentive units vest on July 31, 2016.

(4) Restricted incentive units vest on March 7, 2017.

(5) Restricted incentive units vest on July 23, 2017.

(6) Restricted incentive units vest on January 1, 2018.

(7) Restricted incentive units vest on April 1, 2018.

(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%, which in accordance with SEC rules is the next higher performance level under the award that exceeds 2015 performance. Vesting of these awards is contingent upon the EnLink TSR performance over the applicable performance period measured against a peer group of companies.

Units Vested Table for Fiscal Year 2015

The following table provides information related to the vesting of restricted units and restricted incentive units during fiscal year ended 2015.

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	53,170	$ 1,509,638	(1)	61,971	$ 2,180,858	(5)
Steve J. Hoppe	6,527	$ 174,989	(2)	5,202	$ 174,995	(6)
Mac Hummel	6,527	$ 174,989	(2)	5,202	$ 174,995	(6)
Michael J. Garberding	27,685	$ 782,627	(3)	31,470	$ 1,104,804	(7)
Benjamin D. Lamb	6,703	$ 187,514	(4)	5,680	$ 187,504	(8)

(1) Consists of 38,250 units at $29.01 per unit and 14,920 units at $26.81 per unit.

(2) Consists of 6,527 units at $26.81 per unit.

(3) Consists of 18,360 units at $29.01 per unit and 9,325 units at $26.81 per unit.

(4) Consists of 3,439 units at $29.08 per unit and 3,264 units at $26.81 per unit.

(5) Consists of 50,080 units at $35.56 per unit and 11,891 units at $33.64 per unit.

(6) Consists of 5,202 units at $33.64 per unit.

(7) Consists of 24,038 units at $35.56 per unit and 7,432 units at $33.64 per unit.

(8) Consists of 3,079 units at $32.48 per unit and 2,601 units at $33.64 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 *President and Chief Executive Officer*	3,825,079	30,079	—	5,310,079	6,313,827
Steve J. Hoppe *Executive Vice President and President of Gas Gathering, Processing and Transmission*	1,863,079	30,079	—	1,863,079	2,020,815
Mac Hummel *Executive Vice President and President of Natural Gas Liquids and Crude*	1,865,527	32,527	—	1,865,527	1,855,709
Michael J. Garberding *Executive Vice President and Chief Financial Officer*	2,147,527	32,527	—	2,147,527	3,837,514
Benjamin D. Lamb *Senior Vice President*	646,079	30,079	—	646,079	1,270,427

(1) Each named executive officer is entitled to a lump sum amount equal to two times the Severance Benefit, other than Mr. Lamb who is entitled to one 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 Severance Agreement) or if he terminates employment for good reason (as defined in the Severance 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 Severance Agreement) or he terminates employment without good reason (as defined in the Severance Agreement). The figures shown do not include amounts of base salary previously paid or fringe benefits previously received.

(4) Each named executive officer and one times in the case for Mr. Lamb 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 Severance Agreement) or if he terminates employment for good reason (as defined in the Severance 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 2015.

Compensation of Directors for Fiscal Year 2015

DIRECTOR COMPENSATION

Name	Fees Earned or Paid in Cash ($)	Unit Awards(1) ($)	All Other Compensation(2) ($)	Total ($)
Leldon E. Echols	110,000	99,997	2,729	212,726
Kyle D. Vann	204,500	100,013	5,459	309,972
Mary P. Ricciardello	84,500	99,997	2,729	187,226
Scott A. Griffiths	186,000	100,013	5,459	291,472

(1) Messrs. Echols, Vann, Griffiths and Ms. Ricciardello were granted awards of restricted incentive units of EnLink Midstream Partners, L.P. on March 14, 2014 with a fair market value of $26.72 per unit and that will vest on March 7, 2016 in the following amounts, respectively: 1,871, 3,743, 3,743 and 1,871 Mr. Echols and Ms. Ricciardello were granted awards of restricted units of EnLink Midstream, LLC on March 17, 2015 with a fair market value of $31.02 per unit and that will vest on March 7, 2016 in the following amounts, respectively: 1,612 and 1,612. The amounts shown represent the grant date fair value of awards computed in accordance with FASB ASC 718. See Note 9 to our audited financial statements included in Item 8 herein for the assumptions made in our valuation of such awards. At December 31, 2015, Messrs. Echols, Vann, Griffiths and Ms. Ricciardello held aggregate outstanding restricted incentive unit awards, in the following amounts, respectively: 1,871, 3,743, 3,743 and 1,871. At December 31, 2015, Mr. Echols and Ms. Ricciardello held aggregate outstanding restricted units of EnLink Midstream, LLC in the following amounts, respectively: 1,612 and 1,612.

(2) Other Compensation is comprised of distributions on restricted incentive units and distributions on restricted units.

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. John Richels, Barry E. Davis, Thomas Mitchell, David Hager and Darryl Smette, 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 2015, the Compensation Committee was composed of Scott A. Griffiths and David A. Hager. No member of the Compensation Committee during fiscal 2015 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 2015. 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 the Company or the industry in which it operates, and governance efficiency. Based on these factors, the Board has determined that having John Richels serve as Chairman and Barry E. Davis serve as our Chief Executive Officer is in the best interest of the Company at this time, and that such arrangement makes the best use of each of Messrs. Richels' and 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 the Company's 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 10, 2016, 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 332,270,635 common units (including Class C common units and restricted incentive units that are deemed beneficially owned) and 50,000,000 Series B Convertible Preferred units as of February 10, 2016.

Name of Beneficial Owner(1)	Common Units Beneficially Owned	Percentage of Common Units Beneficially Owned (3)	Series B Convertible Preferred Units Beneficially Owned	Percentage of Preferred Units Beneficially Owned	Total Units Beneficially Owned	Percentage of Total Units Beneficially Owned (4)
Devon Energy Corporation (2)	183,189,051	55.13%	—	—	183,189,051	47.92%
Enfield Holdings, L.P. (5)	—	—	50,000,000	100%	50,000,000	13.08%
Barry E. Davis (6)	427,862	*	—	—	427,862	*
Steve J. Hoppe	4,741	*	—	—	4,741	*
McMillan ("Mac") Hummel	4,741	*	—	—	4,741	*
Michael J. Garberding	94,274	*	—	—	94,274	*
Benjamin D. Lamb	4,877	*	—	—	4,877	*
John Richels	5,825	*	—	—	5,825	*
Leldon E. Echols (7)	24,509	*	—	—	24,509	*
Thomas L. Mitchell	—	*	—	—	—	*
David A. Hager	—	*	—	—	—	*
Darryl G. Smette	—	*	—	—	—	*
Mary P. Ricciardello (8)	3,385	*	—	—	3,385	*
Scott A. Griffiths (9)	6,771	*	—	—	6,771	*
Kyle D. Vann (10)	71,141	*	—	—	71,141	*
Christopher Ortega	—	*	—	—	—	*
Tony Vaughn	—	*	—	—	—	*
All directors and executive officers as a group (15 persons)	648,126	0.20%	—	—	648,126	0.17%

* 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) Devon Gas Services, L.P. ("Devon Gas Services") is the record holder of 86,790,558 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) 64.2% 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.

(3) The percentages reflected in the column below are based on a total of 332,270,635 common units, including 7,075,433 Class C common units and 11,228 restricted incentive units that are deemed beneficially owned. The Class C common units were issued to the sellers in connection with our acquisition of Coronado Midstream Holdings LLC on March 16, 2015. Such sellers continue to hold all of the Class C common units, which represent approximately 2.13% of the outstanding common units (including the Class C common units). The

Class C common units are substantially similar in all respects to the common units, except that distributions paid on the Class C common units may be paid in cash or in additional Class C common units issued in kind, as determined by our general partner in its sole discretion. The Class C common units will automatically convert into common units on a one-for-one basis on the first business day following the date of the distribution for the quarter ended March 31, 2016.

(4) The percentages reflected in the column below are based on a total of 382,270,635 common units, which includes the units described in Footnote 3 and 50,000,000 Series B Convertible Preferred units.

(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) 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 22,638 common units owned of record by Mr. Echols and 1,871 restricted incentive units that are deemed beneficially owned.

(8) Includes 1,514 common units owned of record by Ms. Ricciardello and 1,871 restricted incentive units that are deemed beneficially owned.

(9) Includes 3,028 common units owned of record by Mr. Griffiths and 3,743 restricted incentive units that are deemed beneficially owned.

(10) Includes 67,398 common units owned of record by Mr. Vann and 3,743 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 10, 2016, 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.

The percentage of total common units of EnLink Midstream, LLC beneficially owned is based on a total of 179,911,586 units (including restricted incentive units that are deemed beneficially owned) as of February 10, 2016. The percentage of total shares of Devon Energy Corporation beneficially owned is based on a total of 441,294,735 million shares of common stock outstanding as of February 10, 2016.

	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)	1,817,031	1.01%	—	*
Steve J. Hoppe	3,744	*	43,260	*
McMillan (“Mac”) Hummel	3,737	*	3,557	*
Michael J. Garberding	113,241	*	—	*
Benjamin D. Lamb	—	*	—	*
Leldon E. Echols (3)	27,447	*	—	*
John Richels	—	*	1,224,687	*
Thomas L. Mitchell	—	*	59,295	*
David A. Hager	—	*	400,630	*
Darryl G. Smette	—	*	363,328	*
Mary P. Ricciardello (4)	2,998	*	40,495	*
Scott A. Griffiths	—	*	—	*
Kyle D. Vann	—	*	—	*
Christopher Ortega	—	*	—	*
Tony D. Vaughn	—	*	214,251	*
All directors and executive officers as group (15 persons)	1,968,198	1.09%	2,349,503	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) 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 25,835 common units owned of record by Mr. Echols and 1,612 restricted incentive units that are deemed beneficially owned.

(4) Includes 1,386 common units owned of record by Ms. Ricciardello and 1,612 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)	1,496,169	(2)	$ 8.51	(3)	2,382,017
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 in May 2013 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 9,070,000 common units under the plan.

(2) The number of securities includes 1,253,729 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, 2015 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 26.5% limited partnership interest in us as of December 31, 2015. 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 28.4% majority ownership of our outstanding equity interests as of December 31, 2015. 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, four of our directors, including John Richels, the chairman of the Board, David Hager, Thomas Mitchell and Darryl Smette, 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 $2.1 million and $1.2 million during the years ended December 31, 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 E2 Appalachian and Energy Services through our purchase of the E2 Appalachian Units and the Energy Services

Units, respectively. The total consideration paid by us to EMI for such units included (i) $13.0 million in cash for the Energy Services Units and (ii) $150.0 million in cash and 1,016,322 common units representing limited partner interests in us for the E2 Appalachian Units. Members of the E2 Appalachian management team retain certain Class B Units in E2 Appalachian to provide such member with equity incentives.

Midstream Holdings Drop Down. On February 17, 2015, we acquired the February Transferred Interests from Acacia, a wholly-owned subsidiary of ENLC, in the February EMH Drop Down. As consideration for the February Transferred Interests, we issued 31.6 million of our common units to Acacia.

On May 27, 2015, we acquired the May 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, the Partnership issued2,849,100 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.

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 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 endedDecember 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.

On August 29, 2014, Gas Services assigned its 10-year gathering and processing agreement to Linn Energy in connection with Gas Services' divestiture of certain of its southeastern Oklahoma assets. Such assignment became effective December 1, 2014. Accordingly, beginning on December 1, 2014, Linn Energy assumed all right, title and interest in the gathering and processing agreement and will perform and discharge all obligations under the agreement, which remains in full force and effect. The agreement relates to production dedicated to our Northridge assets in southeastern Oklahoma.

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 2016 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 $107.5 million and $112.3 million, or 2.4% and 3.2%, of our combined revenue for the years ended December 31, 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 minimum volume commitment was executed in June 2014 and the initial term expires July 2019. This agreement accounted for approximately 0.4% and 0.2% of our combined revenues, or $17.8 million and $7.4 million, for the years ended December 31, 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 $0.2 million and $3.0 million for years ended December 31, 2015 and 2014 respectively. We received $0.3 million from Devon under the transition services agreement for the years ended December 31, 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 $13.0 million and $14.3 million to our income from unconsolidated affiliate investment for the years ended December 31, 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 2015.

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% and 0.4% of our combined revenues, or $16.4 million and $15.1 million, for the years ended December 31, 2015 and 2014, respectively.

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.

Preferential Rights Agreement

Upon the closing of the business combination, ENLC entered into a preferential rights agreement with the Partnership and EMI, pursuant to which ENLC and EMI granted us a right of first refusal, for a period of 10 years, with respect to the Access Pipeline Interest, to the extent ENLC in the future obtains such interest pursuant to the first offer agreement. In addition, if ENLC has the opportunity to exercise its right of first offer for the Access Pipeline Interest pursuant to the first offer agreement, but determine not to exercise such right, ENLC will be required to assign such right to us.

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 2015 and 2014, we and Devon incurred approximately $3.0 million and $1.9 million, respectively, in taxes that are subject to the tax sharing agreement at the time of the tax liability was incurred.

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, 2015 and 2014, review of our internal control procedures for the fiscal years ended December 31, 2015 and 2014 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 $2.0 million and $1.8 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, 2015 and 2014 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, 2015 and 2014.

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, 2015 and 2014.

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 2015, 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 the Index to Financial Statements on page F-1.

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	**	—	Contribution Agreement, dated as of October 21, 2013, by and among Devon Energy Corporation, Devon Gas Corporation, Devon Gas Services, L.P., Southwestern Gas Pipeline, Inc., EnLink Midstream Partners, LP and EnLink Midstream Operating, LP (incorporated by reference to Exhibit 2.1 to our Current Report on Form 8-K dated October 21, 2013, filed with the Commission on October 22, 2013, file No. 000-50067).
2.2	**	—	Contribution and Transfer Agreement, dated as of February 17, 2015, by and between EnLink Midstream Partners, LP and Acacia Natural Gas Corp I, Inc. (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated February 17, 2015, filed with the Commission on February 17, 2015).
2.3	**	—	Contribution, Conveyance and Assumption Agreement, dated as of March 23, 2015, by and between EnLink Midstream Partners, LP and Devon Gas Services, L.P. (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated March 23, 2015, filed with the Commission on March 23, 2015).
2.4		—	Contribution and Transfer Agreement, dated as of May 27, 2015, by and between EnLink Midstream Partners, LP and Acacia Natural Gas Corp I, Inc. (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated May 27, 2015, filed with the Commission on May 27, 2015, file No. 001-36340).
2.5	**	—	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).
2.6	**	—	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		—	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).
4.8		—	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-Northridge 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 10.4 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		—	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).

10.6		—	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).
10.7	†	—	Consulting Services Agreement, dated as of March 7, 2014, by and between William W. Davis and EnLink Midstream Operating, LP (incorporated by reference to Exhibit 10.7 to our Current Report on Form 8-K dated March 6, 2014, filed with the Commission on March 11, 2014, file No. 001-36340).
10.8	†	—	EnLink Midstream GP, LLC Long-Term Incentive Plan, as amended and restated on March 7, 2014 (incorporated by reference to Exhibit 10.8 to our Current Report on Form 8-K dated March 6, 2014, filed with the Commission on March 11, 2014, file No. 001-36340).
10.9	†	—	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).
10.10	†	—	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).
10.11		—	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).
10.12	†	—	Separation and Release Agreement, dated October 17, 2014, between EnLink Midstream Operating, LP and Joe A. Davis (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated October 17, 2014, filed with the Commission on October 17, 2014, file No. 001-36340).
10.13	†	—	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).
10.14	†	—	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).
10.15	†	—	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).
10.16	†	—	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).
10.17		—	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).
10.18		—	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).
10.19	†	—	Second Amendment to Employment Agreement, dated August 26, 2014, by and between EnLink Midstream GP, LLC and Michael J. Garberding (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated August 26, 2014, filed with the Commission on August 26, 2014, file No. 001-36340).
10.20		—	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).
10.21	†	—	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).
10.22	†	—	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).

10.23	†	—	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).
10.24	†	—	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).
10.25		—	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).
10.26		—	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, 2015, formatted in XBRL (eXtensible Business Reporting Language): (i) Consolidated Statements of Operations for the years ended December 31, 2015, 2014 and 2013, (ii) Consolidated Balance Sheets as of December 31, 2015 and 2014, (iii) Consolidated Statements of Cash Flows for the years ended December 31, 2015, 2014 and 2013, (iv) Consolidated Statements of Changes in Partners' Equity for the years ended December 31, 2015, 2014 and 2013 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 17th day of February 2016.

EnLink Midstream Partners, LP

By: EnLink Midstream GP, LLC, its general partner

By: /s/ BARRY E. DAVIS

Barry E. Davis,
President and 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	President, Chief Executive Officer and Director (Principal Executive Officer)	February 17, 2016
/s/ JOHN RICHELS John Richels	Chairman of the Board	February 17, 2016
/s/ LELDON E. ECHOLS Leldon E. Echols	Director	February 17, 2016
/s/ THOMAS L. MITCHELL Thomas L. Mitchell	Director	February 17, 2016
/s/ DAVID A. HAGER David A. Hager	Director	February 17, 2016
/s/ DARRYL G. SMETTE Darryl G. Smette	Director	February 17, 2016
/s/ MARY P. RICCIARDELLO Mary P. Ricciardello	Director	February 17, 2016
/s/ SCOTT A. GRIFFITHS Scott A. Griffiths	Director	February 17, 2016
/s/ KYLE D. VANN Kyle D. Vann	Director	February 17, 2016
/s/ MICHAEL J. GARBERDING Michael J. Garberding	Executive Vice President and Chief Financial Officer (Principal Financial and Accounting Officer)	February 17, 2016

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, 2015, 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 ofDecember 31, 2015, 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 page F-3 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, 2015 and 2014, 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, 2015. We also have audited EnLink Midstream Partners, LP's internal control over financial reporting as of December 31, 2015, 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, 2015 and 2014, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2015, 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, 2015 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(g) 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 to the straight-line 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 17, 2016

ENLINK MIDSTREAM PARTNERS, LP
Consolidated Balance Sheets

	December 31,	
	2015	2014
	(In millions, except unit data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 5.9	$ 9.6
Accounts receivable:		
Trade, net of allowance for bad debt of $0.3	37.5	139.0
Accrued revenues and other	268.7	253.3
Related party	111.1	121.6
Fair value of derivative assets	16.8	16.7
Natural gas and natural gas liquids inventory, prepaid expenses and other	32.1	30.8
Total current assets	472.1	571.0
Property and equipment, net of accumulated depreciation of $1,757.6 and $1,426.3, respectively	5,666.8	5,042.8
Intangible assets, net of accumulated amortization of $54.6 and $36.5, respectively	689.9	533.0
Goodwill	987.0	2,257.8
Fair value of derivative assets	—	10.0
Investments in unconsolidated affiliates	274.3	270.8
Other assets, net	25.7	16.6
Total assets	$ 8,115.8	$ 8,702.0
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities:		
Drafts payable	$ 0.5	$ 13.2
Accounts payable	32.7	108.6
Accounts payable to related party	14.8	3.0
Accrued gas, condensate and crude oil purchases	206.7	204.5
Fair value of derivative liabilities	2.9	3.0
Other current liabilities	174.4	149.8
Total current liabilities	432.0	482.1
Long-term debt	3,089.8	2,022.5
Asset retirement obligations	12.9	12.4
Other long-term liabilities	65.9	84.0
Deferred tax liability	73.6	73.1
Fair value of derivative liabilities	0.1	2.0
Redeemable non-controlling interest	7.0	—
Partners' equity:		
Common unitholders (325,090,624 units issued and outstanding at December 31, 2015 and 245,421,549 units issued and outstanding at December 31, 2014)	4,055.8	5,833.3
Class C unitholders (7,075,433 units issued and outstanding at December 31, 2015)	149.4	—
General partner interest (1,594,974 equivalent units outstanding at December 31, 2015 and December 31, 2014)	213.4	180.3
Non-controlling interest	15.9	12.3
Total partners' equity	4,434.5	6,025.9
Commitments and contingencies (Note 14)		
Total liabilities and partners' equity	$ 8,115.8	$ 8,702.0

See accompanying notes to consolidated financial statements.

ENLINK MIDSTREAM PARTNERS, LP
Consolidated Statements of Operations

	Year ended December 31,		
	2015	2014	2013
	(In millions, except per unit data)		
Revenues:			
Product sales	$ 3,253.7	$ 2,159.3	$ 179.4
Product sales-affiliates	119.4	505.6	2,116.5
Midstream services	451.0	253.4	—
Midstream services-affiliates	618.6	567.4	—
Gain on derivatives activity	9.4	22.1	—
Total revenues	4,452.1	3,507.8	2,295.9
Operating costs and expenses:			
Cost of sales (1)	3,245.3	2,494.5	1,736.3
Operating expenses (2)	419.9	283.6	156.2
General and administrative (3)	132.4	94.5	45.1
Depreciation and amortization	387.3	284.3	187.0
(Gain) loss on disposition of property	1.2	(0.1)	—
Impairments	1,563.4	—	—
Gain on litigation settlement	—	(6.1)	—
Total operating costs and expenses	5,749.5	3,150.7	2,124.6
Operating income (loss)	(1,297.4)	357.1	171.3
Other income (expense):			
Interest expense, net of interest income	(102.5)	(47.4)	—
Income from unconsolidated affiliates	20.4	18.9	14.8
Gain on extinguishment of debt	—	3.2	—
Other income (expense)	0.8	(0.5)	—
Total other income (expense)	(81.3)	(25.8)	14.8
Income (loss) from continuing operations before non-controlling interest and income taxes	(1,378.7)	331.3	186.1
Income tax (provision) benefit	0.5	(22.0)	(67.0)
Net income (loss) from continuing operations	(1,378.2)	309.3	119.1
Discontinued operations:			
Income (loss) from discontinued operations, net of tax	—	1.0	(2.3)
Income from discontinued operations attributable to non-controlling interest, net of tax	—	—	(1.3)
Discontinued operations, net of tax	—	1.0	(3.6)
Net income (loss)	(1,378.2)	310.3	115.5
Net loss attributable to the non-controlling interest	(0.4)	(0.2)	—
Net income (loss) attributable to EnLink Midstream Partners, LP	$ (1,377.8)	$ 310.5	$ 115.5
Predecessor interest in net income (loss) (4)	$ —	$ 35.5	$ —
General partner interest in net income	$ 58.0	$ 138.3	$ —
Limited partners' interest in net income (loss) attributable to EnLink Midstream Partners, LP	$ (1,405.2)	$ 136.7	$ —
Class C partners' interest in net loss attributable to EnLink Midstream Partners, LP	$ (30.6)	$ —	$ —
Net income (loss) attributable to EnLink Midstream Partners, LP per limited partners' unit:			
Basic common unit	$ (4.66)	$ 0.59	$ —
Diluted common unit	$ (4.66)	$ 0.59	$ —

(1) Includes $141.3 million, $354.3 million and $1,588.2 million for the year ended December 31, 2015, 2014 and 2013, respectively, of affiliate purchased gas.
(2) Includes $0.5 million, $5.9 million and $36.2 million for the year ended December 31, 2015, 2014 and 2013, respectively, of affiliate operating expenses from Devon.
(3) Includes $0.2 million, $11.6 million and $45.1 million for the year ended December 31, 2015, 2014 and 2013, respectively, of affiliate general and administrative expenses from Devon.
(4) Represents net income attributable to the Predecessor for the periods 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, 2015, 2014 and 2013

	Common Units		Class C Common Units		General Partner Interest		Predecessor Equity	Non-Controlling Interest		Redeemable Non-controlling interest (Temporary Equity)
	$	Units	$	Units	$	Units	$	$	Total	$
					(In millions)					
Balance, December 31, 2012	$ —	—	$ —	—	$ —	—	$ 1,953.3	$ 48.7	$ 2,002.0	—
Distributions to the Predecessor	—	—	—	—	—	—	(285.1)	—	(285.1)	—
Distributions to non-controlling interest	—	—	—	—	—	—	—	(1.6)	(1.6)	—
Sale of non-controlling interest	—	—	—	—	—	—	—	(47.1)	(47.1)	—
Net income (loss)	—	—	—	—	—	—	115.5	—	115.5	—
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 (Note 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

See accompanying notes to consolidated financial statements.

ENLINK MIDSTREAM PARTNERS, LP
Consolidated Statements of Cash Flows

	Year Ended December 31,		
	2015	2014	2013
	(In millions)		
Cash flows from operating activities:			
Net income (loss) from continuing operations	$ (1,378.2)	$ 309.3	$ 119.1
Adjustments to reconcile net income (loss) to net cash provided by operating activities, net of assets acquired or liabilities assumed:			
Depreciation and amortization	387.3	284.3	187.0
Asset impairments	1,563.4	—	—
Accretion expense	0.6	0.5	0.5
Gain on extinguishment of debt	—	(3.2)	—
Non-cash unit-based compensation	35.7	19.4	—
(Gain) loss on disposition of property	1.2	(0.1)	—
Deferred tax expense (benefit)	(3.6)	15.3	35.5
Gain on derivatives recognized in net income	(9.4)	(22.1)	—
Cash settlements on derivatives	17.1	(0.3)	—
Amortization of debt issue costs	3.1	1.7	—
Amortization of premium on notes	(2.9)	(2.9)	—
Redeemable non controlling interest expense	(1.8)	—	—
Distribution of earnings from unconsolidated affiliates	21.6	7.0	10.9
Income from unconsolidated affiliates	(20.4)	(18.9)	(14.8)
Changes in assets and liabilities:			
Accounts receivable, accrued revenue and other	197.4	(85.4)	—
Natural gas and NGLs inventory, prepaid expenses and other	4.2	(6.9)	0.7
Accounts payable, accrued gas and crude oil purchases and other accrued liabilities	(169.7)	(18.3)	(8.6)
Net cash provided by operating activities	645.6	479.4	330.3
Cash flows from investing activities:			
Additions to property and equipment	(572.3)	(796.0)	(244.3)
Acquisition of business, net of cash acquired	(524.2)	(421.1)	—
Proceeds from insurance settlement	2.9	—	—
Proceeds from sale of property	1.0	0.1	—
Investment in unconsolidated affiliates	(25.8)	(5.7)	—
Distribution from unconsolidated affiliates in excess of earnings	21.1	10.9	1.1
Net cash used in investing activities	(1,097.3)	(1,211.8)	(243.2)
Cash flows from financing activities:			
Proceeds from borrowings	3,204.4	3,151.5	—
Payments on borrowings	(2,134.3)	(2,501.3)	—
Payments on capital lease obligations	(3.6)	(3.0)	—
Increase (decrease) in drafts payable	(12.7)	10.2	—
Debt refinancing costs	(9.5)	(18.5)	—
Conversion of restricted units, net of units withheld for taxes	(2.5)	(0.7)	—
Proceeds from issuance of common units to general partner	50.0	—	—
Proceeds from issuance of common units	24.4	412.0	—
Distributions to non-controlling partners	(66.5)	(159.5)	—
Contributions by non-controlling partners	16.4	6.3	—
Distribution to partners	(479.3)	(239.8)	—
Distributions to Predecessor	—	(21.3)	(151.2)
Contribution from Devon	27.8	105.7	—
Proceeds from exercise of unit options	0.1	0.4	—
Distributions to Devon for VEX interests transferred (Note 3)	(166.7)	—	—
Net cash provided by (used in) financing activities	448.0	742.0	(151.2)

Cash flow from discontinued operations:			
Net cash provided by operating activities	—	5.0	31.1
Net cash provided by (used in) investing activities	—	(0.6)	154.2
Net cash used in financing activities-net distributions to Devon and non-controlling interests	—	(4.4)	(136.8)
Net cash provided by discontinued operations	—	—	48.5
Net increase (decrease) in cash and cash equivalents	(3.7)	9.6	(15.6)
Cash and cash equivalents, beginning of year	9.6	—	15.6
Cash and cash equivalents, end of year	$ 5.9	$ 9.6	$ —
Cash paid for interest	$ 109.4	$ 53.8	$ —
Cash paid for income taxes	$ 0.5	$ 7.1	$ —

See accompanying 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 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.

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 70% of the outstanding limited liability company interests in ENLC.

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"). Another wholly-owned subsidiary of ENLC 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 Transferred Interests") to us in a drop down transaction (the "February EMH Drop Down") in exchange for 31,618,311 of our Class D Common Units. On May 27, 2015, Acacia contributed the remaining 25% limited partner interest in Midstream Holdings (the "May Transferred Interests") to us in a drop down transaction (the "May EMH Drop Down" and together with the February 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"). See Note 3 - Acquisitions for further discussion.

(b) Nature of Business

We primarily focus on providing midstream energy services, including gathering, transmission, processing, fractionation, brine services and marketing to producers of natural gas, natural gas liquids ("NGLs"), crude oil and condensate. 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 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 oil from a producer site to an end user. 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 and related transactions discussed in Note 1(a) above 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 income on the statement of operations. 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, processing, transmission, fractionation, condensate stabilization and brine services, 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).

(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 $2.6 million and $1.5 million at December 31, 2015 and 2014, respectively, which approximate the fair value of these imbalances. We had imbalance receivables of$3.6 million and $1.2 million at December 31, 2015 and 2014, 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, 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 the 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.

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

	December 31,	
	2015	**2014**
Transmission assets	$ 1,285.1	$ 1,100.1
Gathering systems	2,999.2	2,391.9
Gas processing plants	2,673.7	2,356.1
Other property and equipment	135.9	379.5
Construction in process	330.5	241.5
Property, plant and equipment	7,424.4	6,469.1
Accumulated depreciation	(1,757.6)	(1,426.3)
Property, plant and equipment, net	$ 5,666.8	$ 5,042.8

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 minimum volume commitments. 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 FASB ASC 250, 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 for the year ended December 31, 2014 by approximately $29.4 million and $0.12 per unit.

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 $331.3 million, $247.8 million and $187.0 million was recorded for the years ended December 31, 2015, 2014 and 2013, 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. We recognized a loss on disposition of assets of $1.2 million for the year ended December 31, 2015, which primarily relates to the retirement of a compressor due to fire damage. As of 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. Additionally, we collected $2.4 million of business interruption proceeds from our insurance carrier which was presented in the Midstream services revenue line item in the Consolidated Statement of Operations as of December 31, 2015.

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 amount of fee based services, the purchase and resale margins and the volume of natural gas, NGL, condensate and crude oil available to the asset, (2) markets available to the asset, (3) operating expenses, and (4) 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 December 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 it does not control the investment but has 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.

(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 31st, 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, 2015, we recognized a goodwill impairment loss totaling $1,328.2 million for our Louisiana, Texas and Crude and Condensate reporting units. 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 which 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 $62.8 million and $80.7 million for the years ended December 31, 2015 and 2014, respectively. We have one delivery contract which 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 purchase 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 FASB ASC 815. Changes in fair value of derivative instruments are recorded in gain (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 statement 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 as of December 31, 2015 of $0.3 million and had no reserve for uncollectible receivables as of December 31,2014.

During the years ended December 31, 2015 and 2014, we had only one customer other than the affiliate transactions that individually represented greater than 10.0% of our consolidated midstream revenues. The customer is located in the Louisiana segment and represented 11.7% and 11.0% of the consolidated revenues for years ended December 31, 2015 and 2014, respectively. The affiliate transactions with Devon represented 16.6%, 30.6% and 92.2% of the consolidated midstream revenues for the years ended December 31, 2015, 2014 and 2013, respectively. As we continue to grow and expand, the relationship between individual customer sales and consolidated total sales is expected to continue to change. 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 December 31, 2014 and 2013, 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 FASB 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 Midstream Holdings.

(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) Other Assets

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 $23.0 million and $16.6 million as of December 31, 2015 and 2014, respectively, are included in other assets, net. Debt issuance costs are amortized into interest expense using the straight-line method over the term of the debt.

(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.

(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 the control of us. 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) Recent Accounting Pronouncements

In January 2016, the FASB issued ASU 2016-01, Financial Instruments-Overall: Recognition and Measurement of Financial Assets and Financial Liabilities ("ASU 2016-01"). Under this new standard, the FASB issued new guidance related to accounting for equity investments, financial liabilities under the fair value option, and the presentation and disclosure requirements for financial instruments. In addition, the FASB clarified guidance related to the valuation allowance assessment when recognizing deferred tax assets resulting from unrealized losses on available-for-sale debt securities. ASU 2016-01 is effective beginning after December 15, 2017 including interim periods within those annual periods. Early adoption is permitted. We are currently evaluating the impact this standard will have on our consolidated financial statements and related disclosures.

In November 2015, the FASB issued ASU 2015-17, Balance Sheet Classification of Deferred Taxes ("ASU 2015-17"). The new standard requires that deferred tax assets and liabilities be classified as noncurrent in a classified statement of financial position. ASU 2015-17 is effective in fiscal years beginning after December 15, 2016, including interim periods within those years. Early adoption is permitted. ASU 2015-17 may be applied either prospectively, for all deferred tax assets and liabilities, or retrospectively. We are currently evaluating the impact this standard will have on our consolidated financial statements and related disclosures.

In September 2015, the FASB issued ASU 2015-16, Business Combinations (Topic 805): Simplifying the Accounting for Measurement-Period Adjustments (“ASU 2015-16”), 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. ASU 2015-16 is effective for public business entities for annual periods, including interim periods within those annual periods, beginning after December 15, 2015. For all other entities, ASU 2015-16 is effective for fiscal years beginning after December 15, 2016, and interim periods within fiscal years beginning after December 15, 2017. Early adoption is permitted. The update is effective for us beginning on January 1, 2016.

In May 2014, the FASB issued ASU 2014-09, Revenue from Contracts with Customers (“ASU 2014-09”). ASU 2014-09 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. The new standard 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. ASU 2014-09 is effective for annual reporting periods beginning after December 15, 2017, including interim periods within that reporting period, and is to be applied retrospectively, with early application permitted for annual reporting periods beginning after December 15, 2016. We are currently evaluating the impact this standard will have on our consolidated financial statements and related disclosures.

In April 2015, the FASB issued ASU 2015-03, Interest – Imputation of Interest: Simplifying the Presentation of Debt Issuance Costs (Topic 835). The update requires debt issuance costs related to a recognized debt liability be presented on the balance sheet as a direct deduction from the carrying amount of that debt liability. The standard requires retrospective application and is effective for us beginning on January 1, 2016.

In April 2015, the FASB issued ASU No. 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 fiscal years. ASU 2015-06 requires retrospective application and early adoption is permitted.

In February 2015, the FASB issued 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 update is effective for us beginning on January 1, 2016, and will have no impact on our consolidated financial statements or related disclosures.

Subject to these evaluations, we have reviewed all recently issued accounting pronouncements that became effective during the year ended December 31, 2015, and have determined that none would have a material impact on our Consolidated Financial Statements.

(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 equity interests (all of which were voting) 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.

Purchase Price Allocation (in millions):		
Assets acquired:		
Property, plant and equipment	$	225.3
Intangibles		13.0
Liabilities assumed:		
Current liabilities		(6.8)
Total purchase price	$	231.5

We recognized intangible assets related to customer relationships. The acquired intangible assets will be amortized on a straight-line basis over the estimated customer contract life of approximately 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 equity interests (all of which were voting) 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 ($87.0 million, net of cash acquired). 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.

Purchase Price Allocation (in millions):		
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 will be 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 and is non-deductible for tax purposes.

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.

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 equity interests (all of which were voting) 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 ($238.9 million, net of cash acquired), 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.

Purchase Price Allocation (in millions):		
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 will be 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 and is non-deductible for tax purposes.

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 equity interests (all of which were voting) in a subsidiary of Matador Resources Company ("Matador"), which has gathering and processing assets operations in the Delaware Basin, for approximately $145.3 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. The purchase price allocation has been prepared on a preliminary basis pending receipt of a final valuation report and is subject to change.

Purchase Price Allocation (in millions):		
Assets acquired:		
Current assets	$	1.9
Property, plant and equipment		35.5
Intangibles		98.8
Goodwill		9.1
Total identifiable net assets	$	145.3

We recognized intangible assets related to customer relationships. The acquired intangible assets will be amortized on a straight-line basis over the estimated customer life of approximately 20 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 and is non-deductible for tax purposes.

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 $40.0 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 EMH Drop Down. As consideration for the February 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 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 described under “Devon Transaction” below.

We accounted for the acquisition of the EMH Drop Downs from Acacia as a transfer between entities under common control in accordance with ASC 805-50-30. As such, the February Transferred Interests and May 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 Statement 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 equity interests (all of which were voting) 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 in 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 described in “Devon Transaction” below.

The following tables present the collective impact of the VEX Drop Down and the EMH Drop Downs as presented in our historical Consolidated Statements of Operations for the years ended December 31, 2015 and 2014:

	Year Ended December 31, 2015			
	Partnership Historical	EMH	VEX	Combined
	(in millions)			
Revenues	$ 4,446.8	$ —	$ 5.3	$ 4,452.1
Net income (loss)	$ (1,380.0)	$ —	$ 1.8	$ (1,378.2)
Net income (loss) attributable to non-controlling interest	$ 14.9	$ (15.3)	$ —	$ (0.4)
Net income (loss) attributable to EnLink Midstream Partners, LP	$ (1,394.9)	$ 15.3	$ 1.8	$ (1,377.8)
General partner interest in net income	$ 40.9	$ 15.3	$ 1.8	$ 58.0

	Year Ended December 31, 2014				
	Partnership Historical	EMH*	E2**	VEX***	Combined
	(in millions)				
Revenues	$ 3,491.8	$ —	$ 8.6	$ 7.4	$ 3,507.8
Net income (loss)	$ 314.9	$ —	$ (2.6)	$ (2.0)	$ 310.3
Net income (loss) attributable to non-controlling interest	$ 131.4	$ (131.4)	$ (0.2)	$ —	$ (0.2)
Net income (loss) attributable to EnLink Midstream Partners, LP	$ 183.5	$ 131.4	$ (2.4)	$ (2.0)	$ 310.5
General partner interest in net income (loss)	$ 11.3	$ 131.4	$ (2.4)	$ (2.0)	$ 138.3

* Represents the Transferred Interests amounts for the period from March 7, 2014 through December 31, 2014.

** Represents the E2 Interests amounts for the period from March 7, 2014 through December 31, 2014.

*** Represents the VEX Interests amounts for the period from February 28, 2014 through December 31, 2014.

Devon Transaction

As discussed in Note 1(a), on March 7, 2014, we acquired, through one of our wholly owned subsidiaries, 50% of the outstanding equity interests in 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 120.5 million units representing our limited partnership. Midstream Holdings owns midstream assets in the Barnett Shale in North Texas and the Cana-Woodford and Arkoma-Woodford Shales in Oklahoma, as well as a contractual right to the economic burdens and benefits of Devon’s 38.75% interest in Gulf Coast Fractionator (“GCF”) in Mt. Belvieu, Texas.

Under the acquisition method of accounting, Midstream Holdings is the acquirer in the business combination because its parent company, Devon, obtained control of us through the indirect control of the general partner. Consequently, Midstream Holdings’ assets and liabilities retained their carrying values and our assets acquired and liabilities assumed by Midstream Holdings as the Predecessor in the business combination have been recorded at their fair values measured as of the acquisition date. The excess of the purchase price over the estimated fair values of our net assets acquired has been recorded as goodwill.

Pro Forma Information

The following unaudited pro forma condensed financial information for the year ended December 31, 2015 and 2014 gives effect to the business combination, Chevron acquisition, Coronado acquisition, LPC acquisition, Matador, 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. Pro forma financial information associated with the business combination and acquisitions is reflected below.

	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.

(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. 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. 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.

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 information, among other factors.

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 involves allocating 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. Through the 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, which is included in impairment expense in the Consolidated Statements of Operations.

We concluded that the fair value of goodwill of our Oklahoma reporting unit exceeded its carrying value, and the entire amount of goodwill disclosed on the Consolidated Balance Sheet associated with this remaining reporting unit is recoverable. Therefore, no other goodwill impairment was identified or recorded for this reporting unit as a result of our annual goodwill assessment.

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. A continuing prolonged period of lower commodity prices and unit prices may adversely affect our estimate of future operating results, which could result in future goodwill impairment charges for our Texas and Crude and Condensate reporting units due to the potential impact on the cash flows of our operations.

The table below provides a summary of our change in carrying amount of goodwill, by assigned reporting unit.

	Texas	Louisiana	Oklahoma	Crude and Condensate	Corporate	Totals
			(in millions)			
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
Year Ended December 31, 2014						
Balance, beginning of period	$ 325.4	$ —	$ 76.3	$ —	$ —	$ 401.7
Acquisitions	842.8	786.8	114.0	112.5	—	1,856.1
Balance, end of period	$ 1,168.2	$ 786.8	$ 190.3	$ 112.5	$ —	$ 2,257.8

(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 2015, we reviewed our various assets groups for impairment due to the triggering events described in the goodwill impairment analysis above. 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. The non-cash impairment charge is included in the impairment expense line item of the Consolidated Statement of Operations. 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.

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, 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
Year Ended December 31, 2014			
Customer relationships, beginning of period	$ —	$ —	$ —
Acquisitions	569.5	—	569.5
Amortization expense	—	(36.5)	(36.5)
Customer relationships, end of period	$ 569.5	$ (36.5)	$ 533.0

The weighted average amortization period for intangible assets is 12.6 years. Amortization expense for intangibles was approximately $56.0 million and $36.5 million for the years ended December 31, 2015 and 2014, respectively.

The following table summarizes our estimated aggregate amortization expense for the next five years (in millions):

2016	$ 46.1
2017	46.1
2018	46.1
2019	46.1
2020	46.1
Thereafter	459.4
Total	$ 689.9

(5) Affiliate Transactions

We engage in various transactions with Devon and other affiliated entities. For the years ended December 31, 2015, 2014 and 2013, Devon was a significant customer to us. Devon accounted for 16.6%, 30.6% and 92.2% of our revenues for the year ended December 31, 2015, 2014 and 2013, respectively. We had an accounts receivable balance related to transactions with Devon of $110.8 million and $121.6 million as of December 31, 2015 and 2014, respectively. Additionally, we had an accounts payable balance related to transactions with Devon of $14.8 million and $3.0 million as of December 31, 2015 and 2014, respectively. Management believes these transactions are executed on terms that are fair and reasonable and are consistent with terms for transactions with nonaffiliated third parties. The amounts related to affiliate transactions are specified in the accompanying financial statements.

Gathering, Processing and Transportation Agreements with Devon

As described in Note 1, 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 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. 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.

Effective December 1, 2014, Gas Services assigned one of its 10-year gathering and processing agreements to Linn Exchange Properties, LLC ("Linn Energy"), which is a subsidiary of Linn Energy, LLC, in connection with Gas Services' divestiture of certain of its southeastern Oklahoma assets. Accordingly, beginning on December 1, 2014, Linn Energy assumed all right, title and interest in the gathering and processing agreement and began performing Gas Services' obligations under the agreement, which relates to production dedicated to our Northridge assets in southeastern Oklahoma and remains in full force and effect.

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 expire between January 2016 and 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.

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 $0.2 million and $3.0 million for years ended December 31, 2015 and 2014, respectively. We received $0.3 million from Devon under the transition services agreement for the year ended December 31, 2015 and 2014, respectively.

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.

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	2013
Continuing Operations:		
Operating revenues - affiliates	$ (436.4)	$ (2,116.5)
Operating expenses - affiliates	340.0	1,669.5
Net affiliate transactions	(96.4)	(447.0)
Capital expenditures	16.2	244.3
Other third-party transactions, net	58.9	51.5
Net third-party transactions	75.1	295.8
Net cash distributions to Devon - continuing operations	(21.3)	(151.2)
Non-cash distribution of net assets to Devon	(6.3)	—
Total net distributions per equity	$ (27.6)	$ (151.2)
Discontinued operations:		
Operating revenues - affiliates	$ (10.4)	$ (84.6)
Operating expenses - affiliates	5.0	32.7
Cash used in financing activities - affiliates	—	(5.6)
Net affiliate transactions	(5.4)	(57.5)
Capital expenditures	0.6	1.1
Other third-party transactions, net	0.4	(72.0)
Net third-party transactions	1.0	(70.9)
Net distributions to Devon and non-controlling interests - discontinued operations	(4.4)	(128.4)
Non-cash distribution of net assets to Devon	(39.9)	—
Total net distributions per equity	$ (44.3)	$ (128.4)
Total distributions- continuing and discontinued operations (1)	$ (71.9)	$ (279.6)

(1) Total distributions- continuing and discontinued operations for the year ended December 31, 2013 of $279.6 million does not include $5.5 million of distributions related to certain assets that weren't transferred to us, which are included in the Distribution to Predecessor line item on the Consolidated Statements of Changes in Partners' Equity.

Share-based compensation costs included in the management services fee charged to Midstream Holdings by Devon were approximately$2.8 million and $12.8 million for the years ended December 31, 2014 and 2013, respectively. Pension, postretirement and employee savings plan costs included in the management services fee charged to us by Devon were approximately $1.6 million and $8.7 million for the years ended December 31, 2014 and 2013, respectively. These amounts are included in general and administrative expenses in the accompanying statements of operations.

Transactions with ENLC

ENLC paid us $2.1 million and $1.2 million during the years ended December 31, 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 issued2,849,100 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, 2015 and 2014, long-term debt consisted of the following (in millions):

	Year Ended December 31, 2015	Year Ended December 31, 2014
Partnership credit facility (due 2020), interest based on Prime and/or LIBOR plus an applicable margin, interest rate at December 31, 2015 and December 31, 2014 was 1.8% and 1.9%, respectively	$ 414.0	$ 237.0
Senior unsecured notes (due 2019), net of discount of $0.4 million at December 31, 2015 and $0.5 million at December 31, 2014, which bear interest at the rate of 2.70%	399.6	399.5
Senior unsecured notes (due 2022), including a premium of $18.9 million at December 31, 2015 and $21.9 million at December 31, 2014, which bear interest at the rate of 7.125%	181.4	184.4
Senior unsecured notes (due 2024), net of premium of $2.9 million at December 31, 2015 and $3.2 million at December 31, 2014, which bear interest at the rate of 4.40%	552.9	553.2
Senior unsecured notes (due 2025), net of discount of $1.2 million at December 31, 2015, which bear interest at the rate of 4.15%	748.8	—
Senior unsecured notes (due 2044), net of discount of $0.2 million at December 31, 2015 and $0.3 million at December 31, 2014, which bear interest at the rate of 5.60%	349.8	349.7
Senior unsecured notes (due 2045), net of discount of $6.9 million at December 31, 2015 and $1.7 million at December 31, 2014, which bear interest at the rate of 5.05%	443.1	298.3
Other debt	0.2	0.4
Debt classified as long-term	$ 3,089.8	$ 2,022.5

Maturities. Maturities for the long-term debt as of December 31, 2015 are as follows (in millions):

2016	$ 0.1
2017	0.1
2018	—
2019	400.0
2020	414.0
Thereafter	2,262.5
Subtotal	3,076.7
Add: net premium	13.1
Total outstanding debt	$ 3,089.8

Credit Facility. On February 20, 2014, we entered into a new $1.0 billion unsecured revolving credit facility, which includes a $500.0 million letter of credit subfacility (the “Partnership credit facility”). On February 5, 2015, we exercised the accordion under our credit facility, increasing the size of the facility to $1.5 billion and also exercised an option to extend the maturity date of our credit facility to March 6, 2020. We also entered into certain amendments to our credit facility pursuant to which 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 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 (as defined in our credit facility, which definition 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 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 as listed below. 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, 2015, 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, 2015, there were $10.9 million in outstanding letters of credit and $414.0 million in outstanding borrowings under our credit facility, leaving approximately $1.1 billion available for future borrowing based on the borrowing capacity of $1.5 billion.

Pricing Level	Debt Ratings	Applicable Rate Commitment Fee	EuroDollar Rate/Letter of Credit	Base Rate +
1	A-/A3 or better	0.100%	1.000%	—%
2	BBB+/Baa1	0.125%	1.125%	0.125%
3	BBB/Baa2	0.175%	1.250%	0.250%
4	BBB-/Baa3	0.225%	1.500%	0.500%
5	BB+/Ba1	0.275%	1.625%	0.625%
6	BB/Ba2 or worse	0.350%	1.750%	0.750%

Senior Unsecured Notes. On March 7, 2014, we recorded $725.0 million in aggregate principal amount of 8.875% senior unsecured notes (the “2018 Notes”) due on February 15, 2018 in the business combination. As a result of the business combination, the 2018 Notes were recorded at fair value in accordance with acquisition accounting at an amount of $761.3 million, including a premium of $36.3 million, as of March 7, 2014.

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 12, 2014, we commenced a tender offer to purchase any and all of the outstanding 2018 Notes. Approximately $536.1 million, or approximately 74%, of the 2018 Notes were validly tendered and on March 19, 2014, we made a payment of approximately $567.4 million for all such tendered 2018 Notes. Also on March 19, 2014, we delivered a notice of redemption for any and all outstanding 2018 Notes. All remaining outstanding 2018 Notes were redeemed on April 18, 2014 for $200.2 million, including accrued interest. We recorded a gain on extinguishment of debt related to the redemption of the 2018 Notes of $0.7 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.

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 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, 2015 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):

	Years Ended December 31,		
	2015	2014	2013
Current income tax expense	$ 3.1	$ 6.7	$ 31.5
Deferred tax expense (benefit)	(3.6)	15.3	35.5
Total income tax expense (benefit)	$ (0.5)	$ 22.0	$ 67.0

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.

The difference between tax expense based on the statutory federal income tax rate and our effective tax expense (benefit) is summarized as follows (in millions):

	Year Ended December 31,
	2013
Expected income tax expense based on federal statutory rate of 35%	$ 65.1
State income taxes (benefit), net of federal benefit and other	1.9
Other taxes (benefit)	—
Total income tax expense (benefit)	$ 67.0

Deferred tax liabilities of $73.6 million and $73.1 million existed for the period ended December 31, 2015 and 2014, respectively. Deferred tax liabilities include $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, 2015, the total amount of unrecognized tax benefits was $1.5 million. There were no unrecognized tax benefits prior to January 1, 2014. A reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows (in millions):

	Year Ended December 31,	
	2015	2014
Beginning Balance, January 1	$ 2.0	$ —
Unrecognized tax positions assumed in merger	—	3.8
Decrease due to prior year tax positions	(0.5)	(2.0)
Increases due to current year tax positions	—	0.2
Ending Balance, December 31	$ 1.5	$ 2.0

Unrecognized tax benefits as of December 31, 2015 of $1.5 million if recognized, would affect the effective tax rate. It is unknown when the remaining uncertain tax position will be resolved.

Per our accounting policy election, penalties and interest related to unrecognized tax benefits is recorded to income tax expense. As of December 31, 2015, tax years 2011 through 2015 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, 2015, we sold an aggregate of 1.3 million common units under the BMO EDA, generating proceeds of approximately $24.4 million (net of approximately $0.3 million of commissions). We used the net proceeds for general partnership purposes. As of December 31, 2015, approximately $317.0 million of common units remain available to be issued under the BMO EDA.

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. For further discussion see Note 3- Acquisitions. The Class C Common Units are substantially similar in all respects to our common units, except that distributions paid on the Class C Common Units may be paid in cash or in additional Class C Common Units issued in kind, as determined by the general partner in its sole discretion. The Class C Common Units will automatically convert into common units on a one-for-one basis on the earlier to occur of (i) the date on which the general partner, in its sole discretion, determines to convert all of the outstanding Class C Common Units into common units and (ii) the first business day following the date of the distribution for the quarter ended March 31, 2016. 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 ("PIK") 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. A distribution on the Class C Common Units of $0.390 per unit was declared for the three months ended December 31, 2015, which will result in the issuance of 209,044 additional Class C Common Units on February 11, 2016.

(c) Class D Common Units

In February 2015, we issued 31,618,311 Class D Common Units to Acacia 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 Acacia 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) 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 is not entitled to its general partner or incentive distributions with respect to the Class C Common Units issued in kind.

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, 2015 and 2014 is provided below:

Declaration period	Distribution/unit		Date paid/payable
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.

(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.

(f) Earnings per Unit and Dilution Computations

As required under FASB ASC 260-10-45-61A, unvested share-based payments that entitle employees to receive non-forfeitable distributions are considered participating securities, as defined in FASB ASC 260-10-20, 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,	
	2015	2014*
Limited partners' interest in net income (loss)	$ (1,405.2)	$ 136.7
Distributed earnings allocated to:		
Common units (1) (2)	$ 465.9	$ 310.0
Unvested restricted units	2.0	1.3
Total distributed earnings	$ 467.9	$ 311.3
Undistributed loss allocated to:		
Common units (2)	$ (1,865.3)	$ (173.9)
Unvested restricted units	(7.8)	(0.7)
Total undistributed loss	$ (1,873.1)	$ (174.6)
Net income (loss) allocated to:		
Common units (2)	$ (1,399.4)	$ 136.1
Unvested restricted units	(5.8)	0.6
Total limited partners' interest in net income (loss)	$ (1,405.2)	$ 136.7
Total basic and diluted net income (loss) per unit:		
Basic	$ (4.66)	$ 0.59
Diluted	$ (4.66)	$ 0.59

* The 2014 amounts consist only of the period from March 7, 2014 through December 31, 2014.

(1) December 31, 2015 and 2014 represents a declared distribution of $0.39 per unit payable on February 11, 2016, and distributions paid of $0.38 per unit on May 14, 2015, $0.385 per unit on August 13, 2015, $0.39 per unit on November 12, 2015, $0.36 per unit on May 14, 2014, $0.365 per unit on August 13, 2014 and $0.37 per unit on November 13, 2014 and $0.375 per unit on February 12, 2015, respectively.

(2) December 31, 2015 includes a partial distribution of $0.15 per unit for Class E Common Units paid on August 13, 2015 and a partial distribution of $0.18 per unit for Class D Common Units paid on May 14, 2015. The 2014 distribution of $0.10 per unit for Class B Units paid on May 14, 2014. The Class B Units converted into common units on a one-for-one basis on May 6, 2014.

The following are the unit amounts used to compute the basic and diluted earnings per limited partner unit for the years endedDecember 31, 2015 and 2014 (in millions):

	Year Ended December 31,	
	2015	**2014***
Basic weighted average units outstanding:		
Weighted average limited partner common units outstanding	301.6	232.8
Weighted average Class C Common Units outstanding	5.5	—
Total weighted average limited partner common units outstanding	307.1	232.8
Diluted weighted average units outstanding:		
Weighted average limited partner basic common units outstanding	307.1	232.8
Dilutive effect of restricted units issued	—	0.4
Total weighted average limited partner diluted common units outstanding	307.1	233.2

* The year ended December 31, 2014 amounts consist only of the period from March 7, 2014 through September 30, 2014.

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 year ended December 31, 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 Note 8(e). 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. The net income allocated to the general partner is as follows (in millions):

	Year Ended December 31,	
	2015	**2014***
Income allocation for incentive distributions	$ 47.5	$ 20.6
Unit-based compensation attributable to ENLC’s restricted units	(18.3)	(10.4)
General partner share of net income (loss)	(6.7)	1.1
General partner interest in drop down transactions	35.5	127.0
General partner interest in net income	$ 58.0	$ 138.3

* 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:

	Year Ended December 31,	
	2015	2014
	(in millions)	
Beginning asset retirement obligations	$ 20.6	$ 7.7
Revisions to existing liabilities	(4.0)	2.2
Liabilities acquired	—	10.2
Accretion	0.6	0.5
Liabilities settled	(3.2)	—
Ending asset retirement obligations	$ 14.0	$ 20.6

Asset retirement obligations of $1.1 million and $8.2 million as of December 31, 2015 and 2014, respectively, are included in Other Current Liabilities.

(10) Investment in Unconsolidated Affiliates

Our unconsolidated investments consisted of a contractual right to the benefits and burdens associated with Devon's38.75% ownership interest in GCF at December 31, 2015, 2014 and 2013 and a 30.6% ownership interest in Howard Energy Partners ("HEP") at December 31, 2015 and 2014.

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	Total
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 (1)			
Contributions	$ —	$ 5.7	$ 5.7
Distributions	$ 11.0	$ 12.7	$ 23.7
Equity in income	$ 17.1	$ 1.8	$ 18.9
December 31, 2013			
Distributions	$ 12.0	$ —	$ 12.0
Equity in income	$ 14.8	$ —	$ 14.8

(1) 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,	
	2015	2014
Gulf Coast Fractionators (1)	$ 52.6	$ 54.1
Howard Energy Partners	221.7	216.7
Total investments in unconsolidated affiliates	$ 274.3	$ 270.8

(1) Devon retained $13.1 million of the undistributed earnings due from GCF, as of March 7, 2014 when the GCF contractual right allocating the benefits and burdens of the 38.75% ownership interest in GCF to us became effective. The $13.1 million of the undistributed earnings was reflected as a reduction in the GCF investment on March 7, 2014.

(11) Employee Incentive Plans

(a) Long-Term Incentive Plans

We account for unit-based compensation in accordance with FASB ASC 718, which requires that compensation related to all unit-based awards, including unit options, be recognized in the consolidated financial statements.

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 our partnership since ENLC has no substantial or managed operating activities other than its interests in us. Amounts recognized in the consolidated financial statements with respect to these plans are as follows (in millions):

	Year Ended December 31,		
	2015	2014	2013
Cost of unit-based compensation allocated to Predecessor general and administrative expense (1)	$ —	$ 2.8	$ 12.8
Cost of unit-based compensation charged to general and administrative expense	30.7	16.7	—
Cost of unit-based compensation charged to operating expense	5.0	2.7	—
Total amount charged to income	$ 35.7	$ 22.2	$ 12.8

(1) Unit-based compensation expense was treated as a contribution by the Predecessor in the Consolidated Statement of Changes in Member's Equity in 2014.

On March 7, 2014, the general partner amended and restated the amended and restated EnLink Midstream GP, LLC Long-Term Incentive Plan (the “GP Plan”) (formerly the Crosstex Energy GP, LLC Long-Term Incentive Plan). Amendments to the GP Plan included a change in name and other technical amendments. The GP Plan provides for the issuance of up to 9,070,000 ENLK common units.

(b) 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, 2015 is provided below:

EnLink Midstream Partners, LP Restricted Incentive Units:	Number of Units	Weighted Average Grant-Date Fair Value
Non-vested, beginning of period	1,022,191	$ 31.25
Granted	596,508	26.50
Vested*	(281,319)	28.79
Forfeited	(83,651)	30.55
Non-vested, end of period	1,253,729	$ 29.59
Aggregate intrinsic value, end of period (in millions)	$ 20.8	

* Vested units include 95,127 units withheld for payroll taxes paid on behalf of employees.

We issued restricted incentive units in the first quarter of 2015 to officers and other employees. These restricted incentive units typically vest at the end of three years. In March 2015, we issued 128,675 restricted incentive units with a fair value of $3.4 million to officers and certain employees as bonus payments for 2014, which vested immediately and are included in the restricted units granted and vested line items above.

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, 2015 and 2014 are provided below (in millions):

	Year Ended December 31,	
EnLink Midstream Partners, LP Restricted Incentive Units:	2015	2014
Aggregate intrinsic value of units vested	$ 7.5	$ 1.8
Fair value of units vested	$ 8.1	$ 1.9

As of December 31, 2015, there was $16.2 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 1.6 years.

(c) EnLink Midstream Partners, LP Performance Units

In March 2015, We and ENLC granted performance awards under the 2014 Long-Term Incentive Plan (the "2014 Plan") and GP 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 with respect to the number of performance units vested. The vesting of units may be between zero and 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 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:	2015
Beginning TSR Price	$ 27.68
Risk-free interest rate	0.99 %
Volatility factor	33.01 %
Distribution yield	5.66 %

The following table presents a summary of our performance units.

	Year Ended December 31, 2015	
EnLink Midstream Partners, LP Performance Units:	Number of Units	Weighted Average Grant-Date Fair Value
Non-Vested, beginning of period	—	$ —
Granted	118,126	35.41
Vested	—	—
Non-vested, end of period	118,126	$ 35.41
Aggregate intrinsic value, end of period (in millions)	$ 2.0	

As of December 31, 2015, there was $3.0 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 two years.

(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, 2015 is provided below:

EnLink Midstream, LLC Restricted Incentive Units:	Number of Units	Weighted Average Grant-Date Fair Value
Non-vested, beginning of period	986,472	$ 37.03
Granted	508,101	31.12
Vested*	(273,791)	35.87
Forfeited	(71,889)	35.55
Non-vested, end of period	1,148,893	$ 34.78
Aggregate intrinsic value, end of period (in millions)	$ 17.3	

* Vested units include 86,635 units withheld for payroll taxes paid on behalf of employees.

ENLC issued restricted incentive units in the first quarter of 2015 to officers and other employees. These restricted incentive units typically vest at the end of three years and are included in restricted incentive units outstanding. In March 2015, ENLC issued 102,543 restricted incentive units with a fair value of $3.4 million to officers and certain employees as bonus payments for 2014, which vested immediately and are included in the restricted units granted and vested line items above.

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, 2015 and 2014 are provided below (in millions):

	Year Ended December 31,	
EnLink Midstream LLC Restricted Incentive Units:	2015	2014
Aggregate intrinsic value of units vested	$ 9.2	$ 3.1
Fair value of units vested	$ 9.8	$ 2.9

As of December 31, 2015, there was $16.6 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 March 2015, ENLC granted performance awards under the 2014 Plan discussed in Note (c) above. At the end of the vesting period, recipients receive distribution equivalents with respect to the number of performance units vested. The vesting of units may be between zero and 200% percent of the units granted depending on EnLink's TSR as compared to the peer group 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 and the designated peer group; (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:	2015
Beginning TSR Price	$ 34.24
Risk-free interest rate	0.99 %
Volatility factor	33.02 %
Distribution yield	2.98 %

The following table presents a summary of the ENLC's performance units.

EnLink Midstream, LLC Performance Units:	Year Ended December 31, 2015 Number of Units	Year Ended December 31, 2015 Weighted Average Grant-Date Fair Value
Non-Vested, beginning of period	—	$ —
Granted	105,080	40.5
Vested	—	—
Non-vested, end of period	105,080	$ 40.5
Aggregate intrinsic value, end of period (in millions)	$ 1.6	

As of December 31, 2015, there was $3.0 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 two years.

(f) Benefit Plan

We sponsor a single employer 401(k) plan whereby we match 100% of every dollar contributed up to 6% of an employee's salary. Contributions of $7.0 million and $5.5 million were made to the plan for the years ended December 31, 2015 and 2014, respectively.

(12) Derivatives

Interest Rate Swaps

We entered into interest rate swaps in April and May 2015 in connection with the issuance of the 2025 Notes in May 2015. Additionally, we entered into interest rate swaps in October and November during the year ended December 31, 2014 in connection with the issuance of the 2024 Notes and 2045 Notes in November 2014.

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, 2015	Year Ended December 31, 2014
Settlement gains on derivatives	$ 3.6	$ 3.6

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 FASB 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 on derivative activity in the Consolidated Statements of Operations relating to commodity swaps are (in millions):

	Year Ended December 31,	
	2015	2014*
Change in fair value of derivatives that are not designated for hedge accounting	$ (7.7)	$ 22.4
Settlement gain (loss) on derivatives	17.1	(0.3)
Net gains related to commodity swaps	$ 9.4	$ 22.1

* Amounts consist only of the period from March 7, 2014 through December 31, 2014.

The fair value of derivative assets and liabilities relating to commodity swaps are as follows (in millions):

	Year Ended December 31,	
	2015	2014
Fair value of derivative assets — current	$ 16.8	$ 16.7
Fair value of derivative assets — long term	—	10.0
Fair value of derivative liabilities — current	(2.9)	(3.0)
Fair value of derivative liabilities — long term	(0.1)	(2.0)
Net fair value of derivatives	$ 13.8	$ 21.7

Set forth below is the summarized notional volumes and fair value of all instruments held for price risk management purposes atDecember 31, 2015. The remaining term of the contracts extend no later than January 2017.

		December 31, 2015		
Commodity	Instruments	Unit	Volume	Fair Value
			(In millions)	
NGL (short contracts)	Swaps	Gallons	(43.9)	$ 14.6
NGL (long contracts)	Swaps	Gallons	24.0	(2.8)
Natural Gas (short contracts)	Swaps	MMBtu	(5.5)	1.4
Natural Gas (long contracts)	Swaps	MMBtu	2.9	0.4
Condensate (short contracts)	Swaps	MMbbls	(0.1)	0.2
Total fair value of derivatives				$ 13.8

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 monitors 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 tour counterparties failed to perform under existing swap contracts, our maximum loss as of December 31, 2015 of $16.8 million would be reduced to$13.8 million due to the offsetting of gross fair value payables against gross fair value receivables as allowed by the ISDAs.

Fair Value of Derivative Instruments

Assets and liabilities related to our derivative contracts are included in the fair value of derivative assets and liabilities and the profit and loss on the mark to market value of these contracts are recorded net as a gain on derivatives in the consolidated statement of operations. We estimate the fair value of all of our derivative contracts using actively quoted prices. The estimated fair value of derivative contracts by maturity date was as follows (in millions):

	Maturity Periods			
	Less than one year	One to two years	More than two years	Total fair value
December 31, 2015	$ 13.9	$ (0.1)	$ —	$ 13.8

(13) Fair Value Measurements

FASB ASC 820 sets forth a framework for measuring fair value and required disclosures about fair value measurements of assets and liabilities. Fair value under FASB 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.

FASB 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.

Net assets measured at fair value on a recurring basis are summarized below (in millions):

	Level 2	
	December 31,	
	2015	2014
Commodity Swaps*	$ 13.8	$ 21.7
Total	$ 13.8	$ 21.7

* Unrealized gains or losses on commodity derivatives qualifying for hedge accounting are recorded in accumulated other comprehensive income at each measurement date. 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 FASB ASC 820.

Fair Value of Financial Instruments

The estimated fair value of our financial instruments has been determined by us 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, 2015		December 31, 2014	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	$ 3,089.8	$ 2,585.5	$ 2,022.5	$ 2,026.1
Obligations under capital lease	$ 16.7	$ 15.6	$ 20.3	$ 19.8

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 $414.0 million and $237.0 million in outstanding borrowings under our revolving credit facility as of December 31, 2015 and 2014, 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, 2015, we had total borrowings of $2.7 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, 2014, we had total borrowings of $1.8 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, 2015 and 2014 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.

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):

2016	$	11.7
2017		9.0
2018		13.9
2019		11.0
2020		8.6
Thereafter		72.7
	$	126.9

Operating lease rental expense for the years ended December 31, 2015, 2014 and 2013 was approximately $66.1 million, $50.8 million and zero, 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 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.

(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"). Our Crude and Condensate segment, which is identified based upon the nature of services provided to customers of the segment, has historically been referred to as our ORV segment. Due to the growth in this segment, including the acquisitions of LPC and VEX, we have renamed this segment to more accurately reflect the assets included therein. We have restated the prior period to include certain crude and condensate activity in the Crude and Condensate segment. 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 investments in HEP and GCF. We evaluate the performance of our operating segments based on operating revenues and segment profits.

Summarized financial information concerning our reportable segments is shown in the following tables:

	Texas	Louisiana	Oklahoma	Crude and Condensate	Corporate	Totals
			(In millions)			
Year Ended December 31, 2015:						
Product sales	$ 320.0	$ 1,527.7	$ 5.0	$ 1,401.0	$ —	$ 3,253.7
Product sales-affiliates	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-affiliates	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-affiliates	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-affiliates	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
Year Ended December 31, 2013:						
Product sales	$ 129.3	$ —	$ 50.1	$ —	$ —	$ 179.4
Product sales-affiliates	1,419.8	—	696.7	—	—	2,116.5
Cost of sales	(1,130.4)	—	(605.9)	—	—	(1,736.3)
Operating expenses	(121.2)	—	(35.0)	—	—	(156.2)
Segment profit	$ 297.5	$ —	$ 105.9	$ —	$ —	$ 403.4
Depreciation and amortization	$ (110.6)	$ —	$ (76.4)	$ —	$ —	$ (187.0)
Goodwill	$ 325.4	$ —	$ 76.3	$ —	$ —	$ 401.7
Capital expenditures	$ 147.0	$ —	$ 66.1	$ —	$ —	$ 213.1

The table below represents information about segment assets as ofDecember 31, 2015 and 2014 (in millions):

	Year Ended December 31,	
Segment Identifiable Assets:	**2015**	**2014**
Texas	$ 3,709.5	$ 3,302.9
Louisiana	2,309.3	3,316.5
Oklahoma	873.4	892.8
Crude and Condensate	898.0	871.8
Corporate	325.6	318.0
Total identifiable assets	$ 8,115.8	$ 8,702.0

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,		
	2015	**2014**	**2013**
Segment profits	$ 786.9	$ 735.8	$ 403.4
General and administrative expenses	(132.4)	(94.5)	(45.1)
Depreciation and amortization	(387.3)	(284.3)	(187.0)
Gain (loss) on disposition of assets	(1.2)	0.1	—
Impairments	(1,563.4)	—	—
Operating income (loss)	$ (1,297.4)	$ 357.1	$ 171.3

(16) Quarterly Financial Data (Unaudited)

Summarized unaudited quarterly financial data is presented below.

	First	Second	Third	Fourth	Total
	(In millions, except per unit data)				
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 the 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)
2014:					
Revenues	$ 723.0	$ 927.2	$ 857.4	$ 1,000.2	$ 3,507.8
Operating income	$ 73.6	$ 91.4	$ 88.2	$ 103.9	$ 357.1
Net income attributable to the EnLink Midstream Partners, LP	$ 53.6	$ 81.8	$ 83.5	$ 91.6	$ 310.5
General partner interest in net income	$ 10.4	$ 43.5	$ 43.0	$ 41.4	$ 138.3
Limited partners' interest in net income attributable to EnLink Midstream Partners, LP	$ 7.7	$ 38.3	$ 40.5	$ 50.2	$ 136.7
Income per limited partner unit-basic	$ 0.03	$ 0.17	$ 0.18	$ 0.21	$ 0.59
Income per limited partner unit-diluted	$ 0.03	$ 0.17	$ 0.18	$ 0.21	$ 0.59

(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	2013
Operating revenues:		
Operating revenues	$ 6.8	$ 42.1
Operating revenues - affiliates	10.5	84.6
Total operating revenues	17.3	126.7
Operating expenses:		
Operating expenses:	15.7	130.3
Total operating expenses	15.7	130.3
Income (loss) before income taxes	1.6	(3.6)
Income tax provision (benefit)	0.6	(1.3)
Net income (loss)	1.0	(2.3)
Net income attributable to non-controlling interest	—	(1.3)
Net income (loss) including non-controlling interest	$ 1.0	$ (3.6)

(18) Supplemental Cash Flow Information

The following schedule summarizes non-cash financing activities for the period presented.

	December 31,
	2015
	(In millions)
Non-cash financing activities:	
Non-cash issuance of common units (1)	$ 180.0
Non-cash issuance of Class C Common Units (1)	$ 180.0
Non-cash adjustment of interest in Midstream Holdings (2)	$ 66.5

(1) 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.

(2) 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.

Also, see Note 5 - Affiliate Transactions for non-cash activities related to Predecessor operations with Devon prior to March 7, 2014.

(19) Other Information

The following tables present additional detail for certain balance sheet captions.

Other Current Liabilities

Other current liabilities consisted of the following:

	Year Ended December 31,	
	2015	2014
	(in millions)	
Accrued interest	$ 23.2	$ 16.9
Accrued wages and benefits, including taxes	27.7	19.7
Accrued ad valorem taxes	27.0	23.2
Capital expenditure accruals	22.3	22.6
Onerous performance obligation	17.0	20.3
Other	57.2	47.1
Other current liabilities	$ 174.4	$ 149.8

(20) Subsequent Events

Tall Oak Acquisition. On January 7, 2016, We and ENLC acquired an 84% and 16% interest, respectively, in subsidiaries of Tall Oak Midstream, LLC for $1.55 billion, subject to certain adjustments. The purchase price will be paid in installments, with the first installment of $1.05 billion paid at closing and the final installment of $500.0 million is due no later than the first anniversary of the closing date with the option to defer $250.0 million of the final installment up to 24 months following the closing date.

The first installment consisted of approximately $1.05 billion and was funded by (a) approximately $788.0 million in cash contributed by us, the majority of which was derived from the proceeds from the issuance of Preferred Units (as defined below), and (b) (i) 15,564,009 common units representing limited liability company interests in ENLC issued directly by ENLC and (ii) approximately $19.5 million in cash contributed by ENLC.

The Tall Oak assets serve gathering and processing needs in the STACK and Central Northern Oklahoma Woodford (“CNOW”) plays in Oklahoma and are supported by long-term, fixed-fee contracts with acreage dedications that have a remaining weighted-average term of approximately 15 years. The assets include two gathering and processing systems and will include a rich gas pipeline currently under construction that will connect the two systems. Due to the timing of the acquisition, we have not yet completed our initial accounting analysis.

Issuance of Preferred Units. On January 7, 2016, we issued an aggregate of 50,000,000 Series B Cumulative Convertible Preferred Units representing our limited partner interests to Enfield Holdings, L.P. in a private placement for a cash purchase price of $15.00 per Preferred Unit (the “Issue Price”), resulting in net proceeds of approximately $725.3 million after fees and deductions. Proceeds from the Private Placement will be used to partially fund our portion of the purchase price payable in connection with the Tall Oak Acquisition.

Exhibit 12.1

RATIO OF EARNINGS TO FIXED CHARGES

	Year Ended December 31,				
	2015	2014	2013	2012	2011
	(In millions)				
Earnings Before Fixed charges:					
Earnings from continuing operations before non-controlling interest or tax	$ (1,378.7)	$ 331.3	$ 186.1	$ 128.3	$ 311.4
Capitalized interest	(7.7)	(11.8)	—	—	—
Amortization of capitalized interest	0.9	0.5	—	—	—
Income from unconsolidated affiliates	(42.7)	(18.9)	(14.8)	(2.0)	(9.3)
Distributed income from unconsolidated affiliates	20.4	23.7	12.0	2.3	8.3
Non-controlling interest	0.4	(0.2)	—	—	—
Total earnings before fixed charges	$ (1,407.4)	$ 324.6	$ 183.3	$ 128.6	$ 310.4
Fixed charges:					
Interest expense	$ 102.5	$ 47.4	$ —	$ —	$ —
Capitalized interest	7.7	11.8	—	—	—
Total fixed charges	$ 110.2	$ 59.2	$ —	$ —	$ —
Total earnings & fixed charges	$ (1,297.2)	$ 383.8	$ 183.3	$ 128.6	$ 310.4
Ratio of earnings to fixed charges	N/A	6.5	N/A	N/A	N/A
Deficiency	$ (1,407.4)	$ —	$ —	$ —	$ —

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
Chandeleur Pipe Line, LLC	Delaware
Clearfield Ohio Holdings, Inc.	Ohio
Coronado Midstream LLC	Texas
E2 Appalachian Compression, LLC	Delaware
E2 Energy Services, LLC	Delaware
E2 Ohio Compression, LLC	Delaware
EnLink Calcasieu, LLC	Delaware
EnLink Crude Marketing, 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 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 North Texas Pipeline, LP	Texas
EnLink Oklahoma Pipeline, LLC	Delaware
EnLink ORV Holdings, Inc.	Delaware
EnLink Pelican, LLC	Delaware
EnLink Permian II, LLC	Texas
EnLink Permian, LLC	Texas
EnLink Processing Services, LLC	Delaware
EnLink Texas NGL Pipeline, LLC	Texas
EnLink Texas Processing, LP	Texas
EnLink TOM Holdings, LP	Delaware

EnLink Tuscaloosa, LLC	Louisiana
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 and 333-188678 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 17, 2016, with respect to the consolidated balance sheets of EnLink Midstream Partners, LP and subsidiaries as of December 31, 2015 and 2014, 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, 2015, and the effectiveness of internal control over financial reporting as of December 31, 2015, which report appears in the December 31, 2015 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 17, 2016

Exhibit 31.1

CERTIFICATIONS

I, Barry E. Davis, President and Chief Executive 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 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,
President and Chief Executive Officer
(principal executive officer)

Date: February 17, 2016

Exhibit 31.2

CERTIFICATIONS

I, Michael J. Garberding, Executive Vice 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,
Executive Vice President and Chief Financial Officer
(principal financial and accounting officer)

Date: February 17, 2016

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, 2015 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 17, 2016

/s/ MICHAEL J. GARBERDING
Michael J. Garberding
Chief Financial Officer

Date: February 17, 2016

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.