EnLink Midstream, LLC
Form 10-K
February 17, 2016

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-K
ý 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
o TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to
Commission file number: 001-36336
ENLINK MIDSTREAM, LLC
(Exact name of registrant as specified in its charter)

Delaware (State of organization)	46-4108528 (I.R.S. Employer Identification No.)
2501 CEDAR SPRINGS DALLAS, TEXAS (Address of principal executive offices)	75201 (Zip Code)

(Registrant's telephone number, including area code)
(214) 953-9500
SECURITIES REGISTERED PURSUANT TO SECTION 12(b) OF THE ACT:

Title of Each Class	Name of Exchange on which Registered
Common Units Representing Limited Liability Company 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 ý No o
Indicate by check mark if registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes o No ý
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 ý No o
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 ý No o
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. o
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 ý	Accelerated filer o	Non-accelerated filer o (Do not check if a	Smaller reporting company o

smaller reporting
company)

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

The aggregate market value of the common units representing limited liability company interests held by non-affiliates of the registrant was approximately $1.5 billion on June 30, 2015, based on $31.09 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 179,901,914 common units outstanding.

DOCUMENTS INCORPORATED BY REFERENCE:

None.

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ENLINK MIDSTREAM, LLC

PART I

Item 1. Business

General

EnLink Midstream, LLC is a Delaware limited liability company formed in October 2013. Effective as of March 7, 2014, EnLink Midstream, Inc. ("EMI") merged with and into a subsidiary wholly owned by us, and Acacia Natural Gas Corp I, Inc. ("Acacia"), formerly a wholly-owned subsidiary of Devon Energy Corporation ("Devon"), merged with and into another subsidiary wholly owned by us (collectively, the "mergers"). Pursuant to the mergers, each of EMI and Acacia became our wholly-owned subsidiaries and we became publicly held. EMI owns common units representing an approximate 6.1% limited partner interest in EnLink Midstream Partners, LP (the "Partnership") as of December 31, 2015 and also owns EnLink Midstream Partners GP, LLC, the general partner of the Partnership (the "General Partner"). At the conclusion of the mergers, Acacia directly owned a 50% limited partner interest in a limited partnership, formerly wholly owned by Devon, that was renamed EnLink Midstream Holdings, LP ("Midstream Holdings"). Concurrently with the consummation of the mergers, a wholly-owned subsidiary of the Partnership acquired the remaining 50% of the outstanding 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 (together with the mergers, the "business combination").

On February 17, 2015, Acacia contributed a 25% interest in Midstream Holdings (the "February Transferred Interests") to the Partnership in a drop down transaction (the "February EMH Drop Down") in exchange for 31.6 million units in the Partnership, representing an approximate 9.5% limited partner interest in the Partnership as of December 31, 2015.

On May 27, 2015, Acacia contributed the remaining 25% limited partner interest in Midstream Holdings (the "May Transferred Interests") to the Partnership 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 36.6 million units in the Partnership, representing an approximate 11.0% limited partner interest in the Partnership as of December 31, 2015. After giving effect to the EMH Drop Downs, the Partnership owns 100% of Midstream Holdings.

Our common units are traded on the New York Stock Exchange ("NYSE") under the symbol "ENLC." 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. In the "Investors" section of our website, we post the following filings 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.

On January 7, 2016, EnLink TOM Holdings, LP ("EnLink TOM Holdings") completed its acquisition of 100% of the issued and outstanding membership interests of subsidiaries of Tall Oak Midstream, LLC ("Tall Oak"). For more information on our acquisition of the Tall Oak subsidiaries and related assets, please see "Item 1. Business -- Recent Growth Developments - Acquisitions" below. We indirectly own a 16% limited partner interest in EnLink TOM Holdings, and the Partnership indirectly owns the remaining 84% limited partner interest. EnLink Energy GP, LLC, the general partner of EnLink TOM Holdings, owns the non-economic general partnership interest.

In this report, the terms "Registrant" as well as the terms "our," "we," and "us," or like terms, are sometimes used as references to EnLink Midstream, LLC and its consolidated subsidiaries. References in this report to "EnLink Midstream Partners, LP", the "Partnership," "ENLK" or like terms refer to EnLink Midstream Partners, LP itself or EnLink Midstream Partners, LP together with its consolidated subsidiaries. "TOM Holdings" is sometimes used to refer to EnLink TOM Holdings, LP itself or to EnLink TOM Holdings, LP together with its consolidated subsidiaries. Finally, because TOM Holdings and its subsidiaries are controlled by the Partnership and have similar operations to the Partnership, references to the "Partnership" in this report should also be read to include TOM Holdings when applicable, including general references to the Partnership's business in the risk factors and otherwise.

ENLINK MIDSTREAM, LLC

Our assets consist of equity interests in the Partnership and TOM Holdings. The Partnership is a publicly traded limited partnership engaged in the gathering, transmission, processing and marketing of natural gas and natural gas liquids, or NGLs, condensate and crude oil, as well as providing crude oil, condensate and brine services to producers.

As of December 31, 2015, our interests in the Partnership consist of the following:

- 88,528,451 common units representing an aggregate 26.5% limited partner interest in the Partnership; and

- 100.0% ownership interest in the General Partner, which owns a 0.5% general partner interest and all of the incentive distribution rights in the Partnership.

The Partnership is required by its partnership agreement to distribute all its cash on hand at the end of each quarter, less reserves established by the General Partner in its sole discretion to provide for the proper conduct of the Partnership's business, as applicable, or to provide for future distributions.

The incentive distribution rights in the Partnership entitle us to receive an increasing percentage of cash distributed by the Partnership as certain target distribution levels are reached. Specifically, they entitle us to receive 13.0% of all cash distributed in a quarter after each unit has received $0.25 for that quarter, 23.0% of all cash distributed after each unit has received $0.3125 for that quarter and 48.0% of all cash distributed after each unit has received $0.375 for that quarter.

We intend to pay distributions to our unitholders on a quarterly basis equal to the cash we receive, if any, from distributions from the Partnership less reserves for expenses, future distributions and other uses of cash, including:

- federal income taxes, which we are required to pay because we are taxed as a corporation;
- the expenses of being a public company;
- other general and administrative expenses;
- capital calls for our interest in Tall Oaks to the extent not covered by our borrowings;
- capital contributions to the Partnership upon the issuance by it of additional partnership securities in order to maintain the General Partner's then-current general partner interest, to the extent the board of directors of the General Partner (the "GP Board") exercises its option to do so; and
- cash reserves the board of directors of EnLink Midstream Manager, LLC, our managing member (the "Managing Member"), believes are prudent to maintain.

Our ability to pay distributions is limited by the Delaware Limited Liability Company Act, which provides that a limited liability company may not pay distributions if, after giving effect to the distribution, the company's liabilities would exceed the fair value of its assets. While our ownership of equity interests in the General Partner and the Partnership are included in our calculation of net assets, the value of these assets may decline to a level where our liabilities would exceed the fair value of our assets if we were to pay distributions, thus prohibiting us from paying distributions under Delaware law.

ENLINK MIDSTREAM PARTNERS, LP

EnLink Midstream Partners, LP is a publicly traded Delaware limited partnership formed in 2002. The Partnership's common units are traded on the NYSE under the symbol "ENLK." The Partnership's business activities are conducted through its subsidiary, EnLink Midstream Operating, LP, a Delaware limited partnership (the "Operating Partnership"), and the subsidiaries of the Operating Partnership. The Partnership's executive offices are located at 2501 Cedar Springs Rd., Dallas, Texas 75201, and its telephone number is (214) 953-9500. The Partnership's Internet address is www.enlink.com. The Partnership posts the following filings in the "Investors" section of its website as soon as reasonably practicable after they are electronically filed with or furnished to the Securities and Exchange Commission: the Partnership's annual reports on Form 10-K; the Partnership's quarterly reports on Form 10-Q; the Partnership's 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 the Partnership's website are available free of charge.

EnLink Midstream GP, LLC, a Delaware limited liability company and our wholly-owned subsidiary, is the Partnership's general partner. The General Partner manages the Partnership's operations and activities.

The following diagram depicts the organization and ownership of the Company and its subsidiaries as of December 31, 2015.

On January 7, 2016, EnLink TOM Holdings, an indirect subsidiary of the 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 the 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 the 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
Bboe = billion Boe
Bcf = billion cubic feet
Boe = six Mcf of gas per Bbl of oil
Btu = British thermal units
CO2= 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 at the Partnership’s 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

The Partnership primarily focuses on providing midstream energy services, including gathering, transmission, processing, fractionation, brine services and marketing, to producers of natural gas, NGLs, crude oil and condensate. The Partnership's 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. The Partnership's operations are based in the United States and its sales are derived from external domestic customers.

The Partnership connects the wells of natural gas producers in its market areas to its gathering systems, processes natural gas for the removal of NGLs, fractionate NGLs into purity products and markets those products for a fee, transports natural gas and ultimately provides natural gas to a variety of markets. The Partnership purchases natural gas from natural gas producers and other supply sources and sells that natural gas to utilities, industrial consumers, other marketers and pipelines. The Partnership operates processing plants that process gas transported to the plants by major interstate pipelines or from its own gathering systems under a variety of fee-based arrangements. The Partnership provides 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. The Partnership's 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. The Partnership's transmission pipelines primarily receive natural gas from its gathering systems and from third party gathering and transmission systems and deliver natural gas to industrial end-users, utilities and other pipelines. The Partnership also has transmission lines that transport NGLs from east Texas and from its south Louisiana processing plants to its fractionators in south Louisiana. Additionally, the Partnership owns 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. The Partnership's 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. The Partnership's processing plants remove NGLs and CO2 from a natural gas stream and its fractionators separate the NGLs into separate NGL products, including ethane, propane, iso-butane, normal butane and natural gasoline.

The Partnership's assets are included in five primary segments:

- Texas. The Partnership's 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. The Partnership's 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. The Partnership's Louisiana assets consist of Louisiana Gas and Processing assets which 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. The Partnership's Louisiana Liquids assets consists of 660 miles of liquids transport lines and four fractionation assets with total fractionation capacity of 198 MBbls/d.
- Crude and Condensate. The Partnership's 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, the Partnership's 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. The Partnership's Corporate assets consist of a contractual right to the benefits and burdens associated with Devon's 38.75% ownership interest in Gulf Coast Fractionators (“GCF”) 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 distributions while growing our business prudently and profitably. We intend to accomplish this objective by having the Partnership execute the following strategies:

- Maintain stable cash flows supported by long-term, fee-based contracts. The Partnership will seek to generate cash flows pursuant to long-term, firm contracts with creditworthy customers. The Partnership will continue to pursue opportunities to increase the fee-based and minimum volume commitment components of its contract portfolio to minimize its direct commodity price exposure.
- Maintain strong financial position. The Partnership believes that maintaining a conservative and balanced capital structure and appropriate leverage and other key financial metrics will afford it better access to the capital markets at a competitive cost of capital. The Partnership also believes a strong financial position provides it the opportunity to grow its business in a prudent manner through the cycles in its industry.
- Execute in our core areas. The Partnership believes its 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. The Partnership expects to grow certain of its systems organically over time by meeting Devon’s and its other customers’ midstream service needs that result from its drilling activity in the Partnership's areas of operation. The Partnership continually evaluates whether to pursue economically attractive organic expansion opportunities in existing or new areas of operation that allow it to leverage its existing infrastructure, operating expertise and customer relationships by constructing and expanding systems to meet new or increased demand for its services.

Our Competitive Strengths

We believe that the Partnership is well-positioned to execute its primary business strategies and to achieve its business objective due to the following competitive strengths:

- Devon’s sponsorship. The Partnership expects its relationship with Devon will continue to provide it 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 the Partnership's business, due to its approximate 70% ownership interest in us and approximate 28% ownership interest in the Partnership as of December 31, 2015. Approximately 50% of the Partnership's gross operating margin was attributable to commercial contracts with Devon in 2015.
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Strategically-located assets. The Partnership's assets are strategically located in strategic producing regions with the potential for increasing throughput volume and cash flow generation. The Partnership's assets are in areas consistent with Devon's strategic focus. The Partnership's asset portfolio includes gathering, transmission, fractionation, processing and stabilization systems that are located in areas in which producer activity is focused on crude oil, condensate and NGLs as well as natural gas. The Partnership has developed or is in the process of developing platforms in Oklahoma, in the Permian Basin in Texas and in southern Louisiana through organic development and acquisitions.

- Stable cash flows. Approximately 96% of the Partnership's combined cash flows were derived from fee-based services with no direct commodity exposure during 2015. The Partnership currently has approximately eight years remaining on fixed-fee gathering and processing agreements with a subsidiary of Devon pursuant to which the Partnership will provide gathering, treating, compression, dehydration, stabilization, processing and fractionation services, as applicable, for natural gas delivered by Devon to Partnership's gathering and processing systems in the Barnett and Cana-Woodford Shales. These agreements provide the Partnership 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 with a remaining term of approximately three years. Additionally, the Partnership's 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 "—Partnership's Contractual Relationship with Devon." The Partnership will continue to focus on contract structures that reduce volatility and support long-term stability of cash flows.
- Integrated midstream services. The Partnership spans 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, stabilizing, storing and selling NGLs, and gathering, transporting, storing and trans-loading crude oil and condensate. The Partnership believes its ability to provide all of these services gives it an advantage in competing for new opportunities because it 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. The Partnership believes its management team has a proven track record of creating value through the development, acquisition, optimization and integration of midstream assets. The Partnership's management team has an average of over 20 years of experience in the energy industry. The Partnership believes this team provides it with a strong foundation for evaluating growth opportunities and operating its assets in a safe, reliable and efficient manner.

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

The Partnership's Contractual Relationship with Devon

The following table includes the Partnership's 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, the Partnership entered into to a five-year minimum transportation volume commitment with Devon related to its Victoria Express Pipeline ("VEX Pipeline"). The volume commitments 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 the Partnership acquired a 16% and 84% interest, respectively, in subsidiaries of 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 the Partnership, a portion of which was derived from the proceeds from the issuance of the Preferred Units (as defined under "Issuance of Preferred Units" below), and (b) (i) 15,564,009 of our common units issued directly by us and (ii) approximately $19.5 million in cash contributed by us.

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 and the Partnership 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 Plant 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, the Partnership 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, the Partnership and Apache jointly funded the development of a new-build processing facility in which each company held a 50-percent undivided ownership interest. The Partnership managed the plant's initial construction and has 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 the Partnership's net processing capacity in the Permian Basin to 343 MMcf/d.

Acquisition of Natural Gas Gathering and Processing Assets. On October 1, 2015, the Partnership 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 predominantly 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, the Partnership 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 the Partnership's 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.

The Partnership 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 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, the Partnership 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, the Partnership plans to make contributions to HEP, primarily to fund its 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, the Partnership 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 of 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, the Partnership constructed three natural gas compression and condensate stabilization facilities during late 2014 and 2015 in Harrison, Monroe and Guernsey counties in Ohio. The Partnership will begin construction on the fourth facility as needed based on available volumes.

Marathon Petroleum Joint Venture. The Partnership has 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 the Partnership's existing Riverside fractionation and terminal complex to Marathon Petroleum's Garyville refinery located on the Mississippi River. This bolt-on project to the Partnership's Cajun-Sibon NGL system is supported by long-term, fee-based contracts with Marathon Petroleum. Under the arrangement, the Partnership 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, Acacia contributed the February Transferred Interests to the Partnership in exchange for 31.6 million of the Partnership's units.

On May 27, 2015, Acacia contributed the May Transferred Interests to the Partnership in exchange for 36.6 million of the Partnership's units. After giving effect to the EMH Drop Downs, the Partnership owns 100% of Midstream Holdings.

VEX Pipeline. On April 1, 2015, the Partnership 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. The Partnership 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 Partnership's 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

The Partnership's assets consist of gathering systems, transmission pipelines, processing facilities, fractionation facilities, stabilization facilities, storage facilities and ancillary assets. The following tables provide information about the Partnership's 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

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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 the Partnership's net contractual right to the burdens and benefits of a 38.75% economic interest in Gulf Coast Fractionators held by Devon.

(2) The Partnership has two small fractionation facilities of 15 MBbls/d each. The Partnership's Mesquite Terminal in the Permian Basin and its 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 the Partnership’s current contracts, it does not earn fractionation fees for operating these fractionation facilities so throughput volumes through these facilities are not captured on a routine basis and are not significant to its operating margins.

Texas Assets. The Partnership's 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. The Partnership's 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. The Partnership's North Texas transmission systems include the following:
- North Texas Pipeline. The Partnership’s 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. The Partnership's 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. The Partnership's North Texas processing systems include the following:
- Bridgeport processing facility. The 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. The Partnership currently has approximately eight years remaining on a fixed-fee processing agreement with Devon pursuant to which the Partnership provides 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. The Partnership's Silver Creek processing complex, located in Weatherford, Azle and Fort Worth, Texas, includes three processing plants. The Partnership's 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. The Partnership's 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. The Partnership's 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. The Partnership's 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. The Partnership's 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, the Partnership currently has approximately eight years remaining on a fixed-fee gathering agreement with Devon pursuant to which the Partnership provides 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, the Partnership is a party to 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. The Partnership currently has approximately eight years remaining on a fixed-fee gathering agreement pursuant to which the Partnership provides 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. The Partnership’s Silver Creek gathering system includes two gathering systems. The Partnership’s 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. The Partnership's 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. The Partnership's 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 facilities. The Partnership's processing facilities include the follow:
- Northridge processing plant. The Partnership's 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 the Partnership pursuant to which it provides 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. The Partnership's 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 the Partnership pursuant to which it provides processing services for natural gas delivered by Devon to the Cana processing facility. This contractual arrangement includes a 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 also provides annual rate escalators.
- Oklahoma gathering system. The Partnership's Oklahoma gathering systems include the following:
- Cana gathering system. The Partnership's 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

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above, has entered into a fixed-fee gathering and processing agreement with the Partnership that covers gathering services on the Cana gathering system.

- Northridge gathering system. The Partnership's 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 the Partnership that covers gathering services on the Northridge gathering system.

Louisiana Assets. The Partnership's 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. The Partnership's 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. The Partnership's 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 the Partnership to process natural gas from this system at its Pelican plant when markets are favorable.
- Blue Water Gas Processing Plant. The Partnership operates and owns 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 the Partnership's 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, the Partnership shut down the Eunice processing plant due to adverse economics driven by low NGL prices and low processing volumes, which the Partnership does 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. The Partnership's 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 the Partnership’s 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 the Partnership's Plaquemine gas processing plant complex and is connected to the Partnership's 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 the Partnership's 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. The Partnership's 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, the Partnership's 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. The Partnership's 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. The Partnership has 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, the Partnership's 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. The Partnership's 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. Its 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. The Partnership's 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. The Partnership is 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, the Partneship 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 CO2, 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,

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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 the Partnership purchases natural gas, crude oil and condensate, we establish a margin normally by selling it for physical delivery to third-party users. The Partnership can also use over-the-counter derivative instruments or enter into future delivery obligations under futures contracts on the NYMEX related to its natural gas purchases. Through these transactions, the Partnership seeks to maintain a position that is balanced between purchases, on the one hand, and sales or future delivery obligations, on the other hand. The Partnership's 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. The Partnership faces 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, as applicable. Its competitors include major integrated and independent exploration and production companies, natural gas producers, interstate and intrastate pipelines, other natural gas, NGLs, 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. Competition varies in different geographic areas.

In marketing natural gas, NGLs, crude oil and condensate the Partnership has 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 its marketing operations.

The Partnership faces 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. The Partnership's competitors may have greater financial resources than it possesses or may be willing to accept lower returns or greater risks. Competition differs by region and by the nature of the business or the project involved.

Natural Gas, NGL, Crude Oil and Condensate Supply

The Partnership's gathering and transmission pipelines have connections with major intrastate and interstate pipelines, which it believes have ample natural gas and NGL supplies in excess of the volumes required for the operation of these systems. The Partnership’s ORV pipeline, terminals, trucks and storage facilities are strategically located in crude oil and condensate producing regions. The Partnership evaluates 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 its gathering systems and assets to determine the availability of natural gas, NGLs, crude oil and condensate supply for its systems and assets and/or obtain a minimum volume commitment from the producer that results in a rate of return on investment. The Partnership does not routinely obtain independent evaluations of reserves dedicated to its systems and assets due to the cost and relatively limited benefit of such evaluations. Accordingly, the Partnership does not have estimates of total reserves dedicated to its systems and assets or the anticipated life of such producing reserves.

Credit Risk and Significant Customers

The Partnership is subject to risk of loss resulting from nonpayment or nonperformance by its customers and other counterparties, such as its lenders and hedging counterparties. The Partnership diligently attempts to ensure that it issues credit to only credit-worthy customers. However, the Partnership's purchase and resale of crude oil, condensate, NGLs and natural gas exposes it 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 the Partnership's overall profitability. Some of the Partnership's customers have filed for bankruptcy protection, and their debts and payments to it 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 the Partnership's customers' liquidity and ability to make payment or perform on their obligations to the Partnership. Furthermore, some of the Partneship's 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 the Partnership. A substantial portion of the Partnership's throughput volumes come from producers that have investment-grade ratings; however, many of its 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 year ended December 31, 2015 and 2014, Devon represented 16.6% and 30.6%, respectively, of the Partnership's consolidated revenues and Dow Hydrocarbons & Resources LLC (“Dow Hydrocarbons”) represented 11.7% and 11.0%, respectively, of the Partnership's consolidated revenues. No other customer represented greater than 10.0% of the Partnership's revenue. The Partnership's operations are dependent on the volume of natural gas that Devon provides to it under commercial agreements, which constitutes a substantial portion of its natural gas supply. For the foreseeable future, the Partnership expects its profitability to be substantially dependent on Devon. Further, the loss of Dow Hydrocarbons as a customer could have a material impact on the Partnership's results of operations if it was not able to sell its products to another customer with similar margins because the gross operating margins received from transactions with Dow Hydrocarbons are material to its total gross operating margin.

Regulation

Interstate Natural Gas Pipelines Regulation. The Partnership owns 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 the Partnership 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 the Partnership's 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 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 FERC are required to comply with numerous regulations related to standards of conduct, market transparency, and market manipulation. FERC’s standards of conduct regulate the manner in which interstate natural gas pipelines may interact with its marketing affiliates (unless FERC has granted a waiver of such standards). 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 the Partnership fail to comply with all applicable FERC-administered statutes, rules, regulations and orders, it could be subject to substantial penalties and fines.

The Partnership also transports 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. The Partnership owns 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 the Partnership’s ORV, VEX and Cajun-Sibon pipeline.

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 the Partnership’s ability to set rates based on its costs or could order the Partnership to reduce its 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 the Partnership’s terms and conditions of service if it determines that they are unjust and unreasonable or unduly discriminatory or preferential.

The rates charged by the Partnership's interstate liquids pipelines may also be affected by the ongoing litigation regarding FERC’s income tax allowance policy. As the Partnership acquires, constructs and operates new liquids assets and expands its liquids transportation business, the classification and regulation of its liquids transportation services are subject to ongoing assessment and change based on the services it provides and determinations by FERC and the courts. Such changes may subject additional services the Partnership provides to regulation by FERC.

Gas Pipeline Regulation. The Partnership's 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.

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, FERC’s civil penalty authority under EPAct 2005 would apply to violations of these rules to the extent applicable to the Partnership's 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. The Partnership owns a number of natural gas pipelines that it believes 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.

The Partnership is 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.

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, FERC’s civil penalty authority under EPAct 2005 would apply to violations of these rules to the extent applicable to the Partnership's 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 the Partnership sells natural gas and NGLs currently are not subject to federal regulation and, for the most part, are not subject to state regulation. The Partnership's 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 the Partnership's natural gas and NGL marketing operations, but we do not believe that the Partnership will be affected by any such FERC action in a manner that is materially different from the natural gas and NGL marketers with whom it competes.

Employee Safety. The Partnership is 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 the Partnership's 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. The Partnership's 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 the Partnership's 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 the Partnership's 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 the Partnership's 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 the Partnership's 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 the Partnership's results of operations or financial positions.

As a follow-up to a PHMSA inspection of facilities and records for the Partnership’s ORV pipeline in December 2012, on November 2, 2015, PHMSA issued a Notice of Probable Violation and Proposed Compliance Order (the “NOPV”) asserting that the Partnership has 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 the Partnership to satisfy the Part 195 requirements applicable to transmission lines but did not propose a penalty. The Partnership disagrees with the assertion of PHMSA that the pipeline meets the definition of a transmission rather than gathering line. Accordingly, on December 30, 2015, the Partnership objected to the NOPV and requested a hearing. The hearing is not yet scheduled and the Partnership cannot predict the outcome of its challenge. In the event the pipeline in question is ultimately treated as a transmission line rather than a gathering line, the Partnership estimates that its 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.

The Partnership owns and operates 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. The Partnership is seeking to recover its losses from responsible parties. The Partnership has sued Texas Brine Company, LLC (“Texas Brine”), the operator of a failed cavern in the area, and its insurers seeking recovery for these losses. The Partnership has 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. The Partnership also filed a claim with its insurers, which the Partnership's insurers denied. The Partnership disputed the denial and intends to proceed with litigation against its insurers. In August 2014, the Partnership 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. The Partnership cannot give assurance that we will be able to fully recover its losses through insurance recovery or claims against responsible parties.

Environmental Matters

General. The Partnership's 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 its suppliers to the Partnership's end-use market customers. The Partnership's 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 the Partnership's industrial sector, the Partnership's 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 the Partnership's 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, the Partnership incurred approximately $1.5 million in clean-up and remediation expenses related to a spill in Ohio. The Partnership 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, the Partnership has incurred approximately $1.8 million to clean-up a spill that occurred in its West Virginia operations. The Partnership is working with state and federal agencies relating to this spill, including providing any required notifications and responding to any inquiries. The Partnership 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 the Partnership's operations, it 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 the Partnership currently anticipates. Moreover, risks of process upsets, accidental releases or spills are associated with possible future operations, and the Partnership 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, the Partnership may be unable to pass on those cost increases to its 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 the Partnership to substantial expenses, 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. The Partnership attempts 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, the Partnership 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, the Partnership 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. The Partnership has not received any notification that it may be potentially responsible for cleanup costs under CERCLA or any analogous federal or state law.

The Partnership also generates, 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 the Partnership that is 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 the Partnership's capital expenditures or plant operating expenses or otherwise impose limits or restrictions on our production and operations.

The Partnership currently owns or leases, has 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 the Partnership 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 the Partnership 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, the Partnership 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 the Partnership's 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 the Partnership's facilities, and impose various controls together with monitoring and reporting requirements. Pursuant to these laws and regulations, the Partnership 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. The Partnership 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 the Partnership's financial condition or operating results, and the requirements are not expected to be more burdensome to the Partnership 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 the Partnership and for other companies in the Partnership's industry. While the Partnership is not able at this time to estimate such additional costs, as is the case with similarly situated entities in the Partnership's industry, they could be significant for the Partnership. Compliance with such rules, as well as any new state rules, may also make it more difficult for the Partnership's suppliers and customers to operate, thereby reducing the volume of natural gas transported through the Partnership's pipelines, which may adversely affect its 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 the Partnership 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 the Partnership's 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 the Partnership.

Federal or state legislative or regulatory initiatives that regulate or restrict emissions of greenhouse gases in areas in which the Partnership conducts business could adversely affect the availability of, or demand for, the products the Partnership stores, transports and processes, and, depending on the particular program adopted, could increase the costs of the Partnership's operations, including costs to operate and maintain its facilities, install new emission controls on its facilities, acquire allowances to authorize its greenhouse gas emissions, pay any taxes related to its greenhouse gas emissions and/or administer and manage a greenhouse gas emissions program. The Partnership may be unable to recover any such lost revenues or increased costs in the rates the Partnership charges its customers, and any such recovery may depend on events beyond the Partnership's 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 the Partnership's revenues or increases in its expenses as a result of climate control initiatives could have adverse effects on the Partnership's business, financial position, results of operations and prospects.

Due to its location, the Partnership’s 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. The Partnership's insurance may not cover all associated losses. The Partnership is 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 its 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 the Partnership is 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 the Partnership's results of operations.

The Partnership operates 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. The Partnership's 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 the Partnership's brine disposal wells may impose substantial costs and restrictions on our brine disposal operations, as well as adversely affect demand for the Partnership's 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 the Partnership operates 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 the Partnership's brine disposal operations.

It is common for the Partnership's 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.

Additional regulatory burdens in the future, whether federal, state or local, could increase the cost of or restrict the ability of the Partnership's customers or suppliers to perform hydraulic fracturing. As a result, any increased federal, state or local regulation could reduce the volumes of natural gas that the Partnership's customers move through its

gathering systems which would materially adversely affect the Partnership's revenues and results of operations.
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

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

Employees

As of December 31, 2015, the Partnership (through its subsidiaries) employed approximately 1,432 full-time employees. Approximately 323 of the Partnership's employees were general and administrative, engineering, accounting and commercial personnel and the remainder were operational employees. The Partnership is not party to any collective bargaining agreements and it has not had any significant labor disputes in the past. The Partnership believes that it has good relations with its 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.

Risks Inherent in an Investment in EnLink Midstream

Devon owns approximately 64.2% of our outstanding common units as of February 10, 2016 and controls the Managing Member, which has sole responsibility for conducting our business and managing our operations. Our manager and its affiliates, including Devon, have conflicts of interest with us and limited duties to us and may favor their own interests to your detriment.

Devon owns and controls the Managing Member and appoints all of the directors of the Managing Member, subject to, in certain circumstances, the approval of a majority of our independent directors and our Chief Executive Officer. Some of the directors of the Managing Member are also directors or officers of Devon. Although the Managing Member has a duty to manage us in a manner it subjectively believes to be in, or not opposed to, our best interests, the directors and officers of the Managing Member also have a duty to manage the Managing Member in a manner that is in the best interests of Devon, in its capacity as the sole member of the Managing Member. Conflicts of interest may arise between Devon and its affiliates, including the Managing Member, on the one hand, and us and our unitholders, on the other hand. In resolving these conflicts of interest, the Managing Member may favor its own interests and the interests of its affiliates over the interests of our unitholders. These conflicts include, among others, the following situations:

- neither our operating agreement nor any other agreement requires Devon to pursue a business strategy that favors us, to enter into any commercial agreements with us or the Partnership, or, except as set forth in a first offer agreement pursuant to which Devon is obligated to offer us a right of first offer with respect to its interest in the Access Pipeline transportation system (the "First Offer Agreement"), to sell any assets to us or the Partnership. Devon's directors and officers have a fiduciary duty to make decisions in the best interests of the owners of Devon, which may be contrary to our interests;
- Devon may be constrained by the terms of its debt instruments from taking actions, or refraining from taking actions, that may be in our best interests;
- Devon, as a major customer of the Partnership, has an economic incentive to cause the Partnership to not seek higher transportation rates and processing fees, even if such higher rates or fees would reflect rates and fees that could be obtained in arm's-length, third-party transactions;
- the Managing Member determines the amount and timing of asset purchases and sales, borrowings, issuance of additional membership interests and reserves, each of which can affect the amount of cash that is available to be distributed to unitholders;
- the Managing Member determines which costs incurred by it are reimbursable by us;

- the Managing Member is allowed to take into account the interests of parties other than us in exercising certain rights under our operating agreement;

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- our operating agreement limits the liability of, and eliminates and replaces the fiduciary duties that would otherwise be owed by, the Managing Member and also restricts the remedies available to our unitholders for actions that, without the provisions of the operating agreement, might constitute breaches of fiduciary duty;
- any future contracts between us, on the one hand, and the Managing Member and its affiliates, on the other, will not be the result of arm's-length negotiations;
- except in limited circumstances, the Managing Member will have the power and authority to conduct our business without unitholder approval;
- disputes may arise under commercial agreements between Devon and us or our subsidiaries, including the Partnership;
- the Managing Member may exercise its right to call and purchase all of our outstanding common units not owned by it and its affiliates if it and its affiliates own more than 90% of our outstanding common units;
- the Managing Member controls the enforcement of obligations owed to us by the Managing Member and its affiliates, including the commercial agreements and the First Offer Agreement with Devon; and
- the Managing Member decides whether to retain separate counsel, accountants or others to perform services for us.

Devon may compete with us.

Devon may compete with us, including by developing or acquiring additional gathering and processing assets. Pursuant to the terms of our operating agreement, the doctrine of corporate opportunity, or any analogous doctrine, does not apply to the Managing Member or any of its affiliates, including Devon and its executive officers and directors. Any such person or entity that becomes aware of a potential transaction, agreement, arrangement or other matter that may be an opportunity for us will not have any duty to communicate or offer such opportunity to us. Any such person or entity will not be liable to us or to any of our members for breach of any fiduciary duty or other duty by reason of the fact that such person or entity pursues or acquires such opportunity for itself, directs such opportunity to another person or entity or does not communicate such opportunity or information to us. This may create actual and potential conflicts of interest between us and affiliates of the Managing Member and result in less than favorable treatment of us and our unitholders.

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

Prior to making distributions on our common units, we will reimburse the Managing Member and its affiliates for all expenses they incur on our behalf. These expenses will include all costs incurred by the Managing Member and its affiliates in managing and operating us, including costs for rendering corporate staff and support services to us, if any. There is no limit on the amount of expenses for which the Managing Member and its affiliates may be reimbursed. Our operating agreement provides that the Managing Member will determine the expenses that are allocable to us. In addition, to the extent the Managing Member incurs obligations on behalf of us, we are obligated to reimburse or indemnify the Managing Member. If we are unable or unwilling to reimburse or indemnify the Managing Member, the Managing Member 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.

Our operating agreement replaces the fiduciary duties otherwise owed to our unitholders by the Managing Member with contractual standards governing its duties.

Our operating agreement contains provisions that eliminate and replace the fiduciary standards that the Managing Member would otherwise be held to by state fiduciary duty law. For example, our operating agreement permits the Managing Member to make a number of decisions, in its individual capacity, as opposed to in its capacity as the Managing Member, or otherwise, free of fiduciary duties to us and our unitholders. This entitles the Managing Member to consider only the interests and factors that it desires, and it has no duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or our members. Examples of decisions that the Managing Member may make in its individual capacity include:

- how to allocate business opportunities among us and its other affiliates;
- whether to exercise its call right;
- how to exercise its voting rights with respect to any membership interests it owns;
- whether or not to consent to any merger or consolidation of us or any amendment to our operating agreement; and
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whether or not the manager should elect to seek the approval of the conflicts committee or the unitholders, or neither, of any conflicted transaction.

By purchasing any of our common units, a unitholder is treated as having consented to the provisions in our operating agreement, including the provisions discussed above.

Our operating agreement restricts the remedies available to holders of our membership interests for actions taken by the Managing Member that might otherwise constitute breaches of fiduciary duty.

Our operating agreement contains provisions that restrict the remedies available to holders of our common units for actions taken by the Managing Member that might otherwise constitute breaches of fiduciary duty under state fiduciary duty law. For example, our operating agreement provides that:

- whenever the Managing Member makes a determination or takes, or declines to take, any other action in its capacity as the Managing Member, the Managing Member is required to make such determination, or take or decline to take such other action, in good faith, and will not be subject to any other or different standard imposed by Delaware law, or any other law, rule or regulation, or at equity;
- the Managing Member will not have any liability to us or our unitholders for decisions made in its capacity as a managing member so long as it acted in good faith, meaning that it subjectively believed that the decision was in, or not opposed to, our best interests;
- our operating agreement is governed by Delaware law and any claims, suits, actions or proceedings:
- arising out of or relating in any way to our operating agreement (including any claims, suits or actions to interpret, apply or enforce the provisions of our operating agreement or the duties, obligations or liabilities among members or of members to us, or the rights or powers of, or restrictions on, the members or the company);
- brought in a derivative manner on our behalf;
- asserting a claim of breach of a fiduciary duty owed by any of our directors, officers or other employees or the Managing Member, or owed by the Managing Member, to us or our members;
- asserting a claim arising pursuant to any provision of the DLLCA; or
- asserting a claim governed by the internal affairs doctrine;
- must be exclusively brought in the Court of Chancery of the State of Delaware (or, if such court does not have subject matter jurisdiction thereof, any other court located in the State of Delaware with subject matter jurisdiction), regardless of whether such claims, suits, actions or proceedings sound in contract, tort, fraud or otherwise, are based on common law, statutory, equitable, legal or other grounds, or are derivative or direct claims. By purchasing our common units, a member is irrevocably consenting to these limitations and provisions regarding claims, suits, actions or proceedings and submitting to the exclusive jurisdiction of the Court of Chancery of the State of Delaware (or such other Delaware courts) in connection with any such claims, suits, actions or proceedings;
- the Managing Member and its officers and directors will not be liable for monetary damages to us or our members resulting from any act or omission unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that the Managing Member or its officers or directors, as the case may be, acted in bad faith or engaged in fraud or willful misconduct, or, in the case of a criminal matter, acted with knowledge that the conduct was unlawful; and
- the Managing Member will not be in breach of its obligations under our operating agreement or its duties to us or our members if a transaction with an affiliate or the resolution of a conflict of interest is:
- approved by the conflicts committee of the board of directors of the Managing Member, although the Managing Member is not obligated to seek such approval; or
- approved by the vote of a majority of our outstanding common units, excluding any common units owned by the Managing Member and its affiliates, although the Managing Member is not obligated to seek such approval.

Our manager will not have any liability to us or our unitholders for decisions whether or not to seek the approval of the conflicts committee of the board of directors of the Managing Member or holders of a majority of our common units, excluding any common units owned by the Managing Member and its affiliates. If an affiliate transaction or the resolution of a conflict of interest is not approved by the holders of our common units or the conflicts committee then it will be presumed that, in making its decision, taking any action or failing to act, the board of directors acted in good faith, and in any proceeding brought by or on behalf of any member or us, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption.

Holders of our common units will have limited voting rights and will not be entitled to elect the Managing Member or the board of directors of the Managing Member, which could reduce the price at which our common units will trade.

Unlike the holders of common stock in a corporation, our unitholders will have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management's decisions regarding our business. Unitholders do not have the right to elect the Managing Member or the board of directors of the Managing Member on an annual or other continuing basis. The board of directors of the Managing Member, including its independent directors, is chosen by the sole member of the Managing Member, subject, in certain circumstances, to the approval of a majority of our independent directors and our Chief Executive Officer. Furthermore, if unitholders are dissatisfied with the performance of the Managing Member, they will have very limited ability to remove the Managing Member. Our operating agreement also contains provisions limiting the ability of unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting the unitholders' ability to influence the manner or direction of management. 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, they cannot initially remove the Managing Member without its consent.

Our unitholders are unable to remove the Managing Member without its consent because the Managing Member and its affiliates own sufficient units to be able to prevent its removal. The vote of the holders of at least 662/3% of all outstanding common units voting together as a single class is required to remove the managing member. As of February 10, 2016, the Managing Member and its affiliates owned approximately 65.3% of the outstanding EnLink Midstream Common Units.

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

Unitholders' voting rights are further restricted by our operating agreement, which provides that any units held by a person that owns 20% or more of any class of units, other than the Managing Member, its affiliates, their transferees and persons who acquired such units with the prior approval of the board of directors of the Managing Member, cannot vote on any matter.

Control of the Managing Member may be transferred to a third party without unitholder consent.

Our manager may transfer its managing member interest to a third party in a merger or in a sale of all or substantially all of its assets without the consent of our unitholders. Furthermore, our operating agreement does not restrict the ability of Devon to transfer all or a portion of the ownership interest in the Managing Member to a third party. If the managing member interest were transferred, the new owner of the Managing Member would then be in a position to replace the board of directors and officers of the Managing Member with its own choices and thereby exert significant control over the decisions made by such board of directors and officers. This effectively permits a "change of control" of the Managing Member without the vote or consent of the unitholders.

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

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

- each unitholder's proportionate ownership interest in us will decrease;
- the amount of 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 our common units may decline.

Devon may sell our common units in the public markets or otherwise, which sales could have an adverse impact on the trading price of our common units.

As of February 10, 2016, Devon held 115,495,669 common units. Additionally, we have agreed to provide Devon with certain registration rights with respect to the common units held by it. The sale of these units could have an adverse impact on the price of the our common units or on any trading market that may develop.

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

If at any time the Managing Member and its affiliates own more than 90% of our common units, the Managing Member 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 our common units held by unaffiliated persons at a price equal to the greater of (1) the average of the daily closing price of our common units over the 20 trading days preceding the date three days before notice of exercise of the call right is first mailed and (2) the highest per-unit price paid by the Managing Member 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, unitholders may be required to sell their common units at an undesirable time or price and may not receive any return or a negative return on their investment. Unitholders may also incur a tax liability upon a sale of their units. Our manager is not obligated to obtain a fairness opinion regarding the value of our common nits to be repurchased by it upon exercise of the call right. There is no restriction in our operating agreement that prevents the Managing Member from issuing additional common units and exercising its call right. If the Managing Member exercised its call right, the effect would be to take us private. As of February 10, 2016, Devon owned an aggregate of approximately 64.2% of our common units.

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 the DLLCA, a limited liability company may not make a distribution to a member if, after the distribution, all liabilities of the limited liability company, other than liabilities to members on account of their membership interests and liabilities for which the recourse of creditors is limited to specific property of the company, would exceed the fair value of the assets of the limited liability company. For the purpose of determining the fair value of the assets of a limited liability company, the DLLCA 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 liability company only to the extent that the fair value of that property exceeds the non-recourse liability. The DLLCA provides that a member who receives a distribution and knew at the time of the distribution that the distribution was in violation of the DLLCA will be liable to the limited liability company for the amount of the distribution for three years.

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

As of February 10, 2016, only approximately 34.7% of our common units are 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.”

We are a “controlled company” within the meaning of NYSE rules and, as a result, we qualify for, and rely on, exemptions from some of the listing requirements with respect to independent directors.

Because Devon controls more than 50% of the voting power for the election of directors of the Managing Member, we are a controlled company within the meaning of NYSE rules, which exempt controlled companies from the following corporate governance requirements:

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

- the requirement that we have written charters for the nominating, corporate governance and compensation committees addressing the committees’ responsibilities and annual performance evaluations.

For so long as we remain a controlled company, we will not be required to have a majority of independent directors or nominating, corporate governance or compensation committees. Accordingly, you may not have the same protections afforded to stockholders of companies that are subject to all of the NYSE corporate governance requirements.

Our cash flow consists almost exclusively of distributions from the Partnership.

Currently, our only cash-generating assets are our partnership interests in the Partnership. Our cash flow is therefore completely dependent upon the ability of the Partnership to make distributions to its partners. Accordingly, you should read and consider the risk factors described under the caption "Risks Inherent in the Partnership's Business." The amount of cash that the Partnership can distribute to its partners, including us, each quarter principally depends upon the amount of cash it generates from its operations, which will fluctuate from quarter to quarter based on, among other things:

- the amount of natural gas transported in its gathering and transmission pipelines;
- the level of the Partnership's processing operations;
- the fees the Partnership charges and the margins it realizes for its services;
- the prices of, levels of production of and demand for crude oil, condensate, NGLs and natural gas;
- the volume of natural gas the Partnership gathers, compresses, processes, transports and sells, the volume of NGLs the Partnership processes or fractionates and sells, the volume of crude oil the Partnership handles at its crude terminals, the volume of crude oil and condensate the Partnership gathers, transports, purchases and sells, the volumes of condensate stabilized and the volumes of brine the Partnership disposes;
- the relationship between natural gas and NGL prices; and
- the Partnership's level of operating costs.

In addition, the actual amount of cash the Partnership will have available for distribution will depend on other factors, some of which are beyond its control, including:

- the level of capital expenditures the Partnership makes;
- the cost of acquisitions, if any;
- the Partnership's debt service requirements;
- fluctuations in its working capital needs;
- the Partnership's ability to make working capital borrowings under its bank credit facility to pay distributions;
- prevailing economic conditions; and
- the amount of cash reserves established by its respective general partners in its sole discretion for the proper conduct of business.

Because of these factors, the Partnership may not be able, or may not have sufficient available cash to pay distributions to unitholders each quarter. Furthermore, you should also be aware that the amount of cash the Partnership has available for distribution depends primarily upon its cash flows, including cash flow from financial reserves and working capital borrowings, and is not solely a function of profitability, which will be affected by non-cash items. As a result, the Partnership may make cash distributions during periods when it records losses and may not make cash distributions during periods when it records net income.

Although we control the Partnership, the General Partner owes fiduciary duties to the Partnership and the unitholders.

Conflicts of interest exist and may arise in the future as a result of the relationship between us and our affiliates, including the General Partner, on the one hand, and the Partnership and its limited partners, on the other hand. The directors and officers of EnLink Midstream GP, LLC have fiduciary duties to manage the General Partner in a manner beneficial to us, its owner. At the same time, the General Partner has a fiduciary duty to manage the Partnership in a manner beneficial to the Partnership and its limited partners. The board of directors of EnLink Midstream GP, LLC will resolve any such conflict and has broad latitude to consider the interests of all parties to the conflict. The resolution of these conflicts may not always be in our best interest or that of our unitholders.

For example, conflicts of interest may arise in the following situations:

- the allocation of shared overhead expenses to the Partnership and us;
- the interpretation and enforcement of contractual obligations between us and our affiliates, on the one hand, and the Partnership, on the other hand;
- the determination of the amount of cash to be distributed to the Partnership's partners and the amount of cash to be reserved for the future conduct of the Partnership's business;

- the determination whether to make borrowings under the Partnership’s credit facility to pay distributions to partners; and
- any decision we make in the future to engage in activities in competition with the Partnership.

If the General Partner is not fully reimbursed or indemnified for obligations and liabilities it incurs in managing the business and affairs of the Partnership, its value, and therefore the value of our common units, could decline.

The General Partner may make expenditures on behalf of the Partnership for which it will seek reimbursement from the Partnership. In addition, under Delaware law, the General Partner, in its capacity as the General Partner of the Partnership, has unlimited liability for the obligations of the Partnership, such as its debts and environmental liabilities, except for those contractual obligations of the Partnership that are expressly made without recourse to the General Partner. To the extent the General Partner incurs obligations on behalf of the Partnership, it is entitled to be reimbursed or indemnified by the Partnership. In the event that the Partnership is unable or unwilling to reimburse or indemnify the General Partner, the General Partner may be unable to satisfy these liabilities or obligations, which would reduce its value and therefore the value of our common units.

If in the future we cease to manage and control the Partnership, we may be deemed to be an investment company under the Investment Company Act of 1940.

If we cease to manage and control the Partnership and are deemed to be an investment company under the Investment Company Act of 1940, we would either have to register as an investment company under the Investment Company Act of 1940, obtain exemptive relief from the SEC or modify our organizational structure or our contractual rights so as to fall outside the definition of an investment company. Registering as an investment company could, among other things, materially limit our ability to engage in transactions with affiliates, including the purchase and sale of certain securities or other property to or from our affiliates, restrict our ability to borrow funds or engage in other transactions involving leverage and require us to add additional directors who are independent of us and our affiliates, and adversely affect the price of our common units.

We are treated as a corporation subject to entity level federal and state income taxation. Any such entity level income taxes will reduce the amount of cash available for distribution to you.

We are treated as a corporation for tax purposes that is required to pay federal and state income tax on our taxable income at corporate rates. Historically, we have had net operating losses that eliminated substantially all of our taxable income and, thus, we historically have not had to pay material amounts of income taxes. We anticipate generating net operating losses for tax purposes during 2016, and as a result, do not expect to incur material amounts of federal and state income tax liabilities. In the event we do generate taxable income, federal and state income tax liabilities will reduce the cash available for distribution to our unitholders.

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

Our credit agreement contains, 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. In addition, our credit facility requires us to satisfy and maintain specified financial ratios and other financial condition tests. Our ability to meet those financial ratios and tests can be affected by events beyond our control, and we cannot assure you that we will meet those ratios and tests.

A breach of any of these covenants could result in an event of default under our credit facility. Upon the occurrence of such an event of default, all amounts outstanding under the credit facility could be declared to be immediately due and payable and all applicable commitments to extend further credit could be terminated. If we are unable to repay the accelerated debt under our credit facility, the lenders could proceed against the collateral granted to them to secure that indebtedness. We have pledged the Partnership common units and the 100% membership interest in the General Partner that are indirectly held by us and our 100% equity interest in each of our wholly-owned subsidiaries as collateral under our credit facility. If indebtedness under our credit facility 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 our credit facility and any future financing agreements may adversely affect our ability to finance future operations or capital needs or to engage in other business activities.

Certain events of default under the Partnership’s credit facility, the occurrence of certain bankruptcy events affecting the Partnership or our failure to continue to control the Partnership could constitute an event of default under our credit facility.

Under the terms of our credit facility, certain events of default under the Partnership’s credit facility could constitute an event of default under our credit facility. Additionally, certain events of default under our credit facility relate specifically to events relating to the Partnership, including certain bankruptcy events affecting the Partnership or any event that causes us to no longer indirectly control the Partnership. Additionally, any default by the Partnership under the terms of its credit facility could limit its ability to make distributions to us.

Risks Inherent in the Partnership's Business

The Partnership is dependent on Devon for substantially all of the natural gas that it gathers, processes and transports. After the minimum volume commitments from Devon expire in 2018, a material decline in the volumes of natural gas that the Partnership gathers, processes and transports for Devon could result in a material decline in the Partnership's operating results and cash available for distribution.

The Partnership relies on Devon for a substantial portion of its natural gas supply. For the year ended December 31, 2015, Devon represented a 16.6% of our consolidated revenues. In order to minimize volumetric exposure, in March 2014 the Partnership 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 the Partnership gathers and transports on its 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 the Partnership's is strategically more attractive. A shift in Devon’s focus away from the Partnership's areas of operation could result in reduced throughput on the Partnership's 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, the Partnership recognized $3.8 million under the minimum volume commitments attributable to its Texas Segment because volumes have been below the minimum level since August 2015. The Partnership also recognized $20.1 million under the minimum volume commitments attributable to its 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 the Partnership is substantially dependent on Devon as its primary customer and through Devon’s control of us and our control of the 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 the Partnership and 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 or the Partnership’s borrowings.

The Partnership is substantially dependent on Devon as its primary customer and through Devon’s control of us and our control of the General Partner, and we expect the Partnership to derive a substantial majority of its gross operating margin from Devon for the foreseeable future. As a result, any event, whether in the Partnership's 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 the Partnership's 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, the Partnership is subject to the risk of non-payment or non-performance by Devon, including with respect to the Partnership's 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 the Partnership's gathering and processing agreements. Additionally, due to our relationship with Devon, our or the Partnership’s 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 or the Partnership’s 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 or the Partnership’s 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 the Partnership's gathering, transmission, processing, crude oil, condensate, natural gas and NGL services businesses would reduce its ability to make distributions to its unitholders.

The Partnership relies exclusively on the revenues generated from its gathering, transmission, processing, fractionation, crude oil, natural gas, condensate and NGL services businesses and as a result its 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 the Partnership's financial condition and its ability to make distributions to its unitholders.

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

The Partnership's revenue-producing operations are geographically concentrated in the Barnett Shale, causing it to be disproportionally exposed to risks associated with regional factors. Specifically, the Partnership's operations in the Barnett Shale accounted for approximately 17.4% of its consolidated revenues for the year ended December 31, 2015. The concentration of the Partnership's 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 the Partnership's 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 the Partnership's financial condition and results of operations.

The Partnership must continually compete for crude oil, condensate and natural gas supplies, and any decrease in supplies of such commodities could adversely affect the Partnership's financial condition and results of operations.

In order to maintain or increase throughput levels in the Partnership's natural gas gathering systems and asset utilization rates at its processing plants and to fulfill its current sales commitments, the Partnership must continually contract for new product supplies. The Partnership may not be able to obtain additional contracts for crude oil, condensate, natural gas and NGL supplies. The primary factors affecting the Partnership's ability to connect new wells to its gathering facilities include the Partnership's success in contracting for existing supplies that are not committed to other systems and the level of drilling activity near its gathering systems. If the Partnership is unable to maintain or increase the volumes on its systems by accessing new supplies to offset the natural decline in reserves, the Partnership's business and financial results could be materially, adversely affected. In addition, the Partnership's future growth will depend in part upon whether it can contract for additional supplies at a greater rate than the rate of natural decline in its 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, the Partnership has 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 the Partnership's 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 the Partnership's processing plants. The Partnership has no control over producers and depends 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 the Partnership's 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 the Partnership's results of operations and financial position.

Any decrease in the volumes that the Partnership gathers, processes, fractionates or transports would adversely affect its financial condition, results of operations and cash flows.

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

- environmental or other governmental regulations;
- weather conditions;
- increases in storage levels of natural gas and NGLs;
- increased use of alternative energy sources;
- decreased demand for natural gas and NGLs;

- 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 the Partnership's systems; and
- availability and adequacy of infrastructure to gather and process supply into and out of the Partnership's systems.

The volumes of natural gas, crude oil, condensate and NGLs gathered, processed, fractionated and transported on the Partnership's assets also depend on the production from the regions that supply its 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 the Partnership's systems, the Partnership must obtain new sources of natural gas, crude oil, condensate and NGLs. The primary factors affecting the Partnership's 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 the Partnership's areas of operation, (ii) the Partnership's ability to compete for volumes from new wells and (iii) the Partnership's ability to compete successfully for volumes from sources connected to other pipelines. The Partnership has no control over the level of drilling activity in its areas of operation, the amount of reserves associated with wells connected to its systems or the rate at which production from a well declines. In addition, the Partnership has no control over producers or its 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 the Partnership accounts 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 the Partnership's 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.

The Partnership's 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 the Partnership's cash flows, results of operations and financial condition.

The construction of additions or modifications to the Partnership's existing systems and the construction of new midstream assets involves numerous regulatory, environmental, political and legal uncertainties beyond its control and may require the expenditure of significant amounts of capital. Financing may not be available on economically acceptable terms or at all. If the Partnership undertakes these projects, it may not be able to complete them on schedule, at the budgeted cost or at all. Moreover, the Partnership's revenues may not increase due to the successful construction of a particular project. For instance, if the Partnership expands a pipeline or constructs a new pipeline, the construction may occur over an extended period of time, and it may not receive any material increases in revenues promptly following completion of a project or at all. Moreover, the Partnership 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 its expected investment return, which could adversely affect the Partnership's results of operations and financial condition. In addition, the construction of additions to the Partnership's existing gathering and processing assets will generally require it to obtain new rights-of-way and permits prior to constructing new pipelines or facilities. The Partnership may be unable to timely obtain such rights-of-way or permits to connect new product supplies to its existing gathering lines or capitalize on other attractive expansion opportunities. Additionally, it may become more expensive for the Partnership 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, the Partnership's cash flows could be adversely affected.

Construction of the Partnership's major development projects subjects it to risks of construction delays, cost over-runs, limitations on its growth and negative effects on its operating results, liquidity and financial condition.

The Partnership is 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 the Partnership's 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 the Partnership's business, financial condition, results of operations and liquidity. The construction of pipelines and gathering and processing and fractionation facilities requires the expenditure of significant amounts of capital, which may exceed the Partnership's 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 the Partnership's estimates, its liquidity and capital position could be adversely affected. This level of development activity requires significant effort from the Partnership's management and technical personnel and places additional requirements on its financial resources and internal financial controls. The Partnership 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 the Partnership's credit ratings could increase its financing costs and the cost of maintaining certain contractual relationships.

The Partnership cannot assure you that its 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 downgraded the Partnership to a BBB- credit rating, and the Partnership’s credit rating is currently under review by Moody’s Investors Service. Any future downgrade could increase the cost of borrowings under the Partnership's 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 the Partnership and its subsidiaries;
- the Partnership's subsidiaries to guarantee such debt and certain existing debt, including its senior notes;
- the Partnership and its subsidiaries to provide collateral to secure such debt; and
- the Partnership or its subsidiaries to post cash collateral or letters of credit under its hedging arrangements or in order to purchase commodities or obtain trade credit.

Any increase in the Partnership's financing costs or additional or more restrictive covenants resulting from a credit rating downgrade could adversely affect its 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 the Partnership were experiencing significant working capital requirements or otherwise lacked liquidity, its results of operations and its ability to make cash distributions to unitholders could be adversely affected.

The Partnership typically does not obtain independent evaluations of hydrocarbon reserves; therefore, volumes the Partnership service in the future could be less than anticipated.

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

The Partnership may not be successful in balancing its purchases and sales.

The Partnership is a party to certain long-term gas, NGL and condensate sales commitments that it satisfies through supplies purchased under long-term gas, NGL and condensate purchase agreements. When the Partnership enters into those arrangements, its sales obligations generally match its purchase obligations. However, over time the supplies that the Partnership has under contract may decline due to reduced drilling or other causes and the Partnership 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 the Partnership's purchases and sales not to be balanced. If the Partnership's purchases and sales are not balanced, it will face increased exposure to commodity price risks and could have increased volatility in its operating income.

The Partnership 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 the Partnership's margins or even result in losses. For example, the Partnership is a party to one contract with a term to 2019 to supply approximately 150,000 MMBtu/d of gas. The Partnership buys gas for this contract on several different production-area indices on its NTPL and sell the gas into a different market area index. The Partnership realizes 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.

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

The Partnership is subject to significant risks due to fluctuations in commodity prices. The Partnership is directly exposed to these risks primarily in the gas processing and NGL fractionation components of its business. For the year ended December 31, 2015, approximately 2.8% of the Partnership's total gross operating margin was generated under percent of liquids contracts and percent of proceeds contracts. Under percent of liquids contracts the Partnership receives 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, the Partnership's 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.

The Partnership also realizes processing gross operating margins under processing margin contracts. For the year ended December 31, 2015, approximately 0.7% of the Partnership's total gross operating margin was generated under processing margin contracts. The Partnership has a number of processing margin contracts for activities at its Plaquemine and Pelican processing plants. Under this type of contract, the Partnership pays the producer for the full amount of inlet gas to the plant, and it makes 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”). The Partnership’s margins from these contracts can be greatly reduced or eliminated during periods of high natural gas prices relative to liquids prices.

The Partnership is 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 its assets and on its margins for transportation between certain market centers. Low prices for these products have reduced the demand for the Partnership's services and volumes on its systems, and continued low prices may reduce such demand even further. Although the majority of the Partnership's NGL fractionation business is under fee-based arrangements, a portion of its business is exposed to commodity price risk because it realizes a margin due to product upgrades associated with its Cajun-Sibon fractionation business. For the year ended December 31, 2015, margins realized associated with product upgrades represented less than 1% of the Partnership's gross operating margin.

The prices of crude oil, condensate, 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.

The markets and prices for crude oil, condensate, natural gas and NGLs depend upon factors beyond the Partnership's 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 the Partnership's gross operating margin and cash flows to vary widely from period to period. The Partnership’s hedging strategies may not be sufficient to offset price volatility risk and, in any event, do not cover all of the Partnership's throughput volumes. Moreover, hedges are subject to inherent risks, which we describe in “Item 7A. Quantitative and Qualitative Disclosure about Market Risk.” The Partnership’s use of derivative financial instruments does not eliminate the Partnership's 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 the Partnership connects, the Partnership's gross operating margin and cash flow could be adversely affected.

The Partnership's gathering, processing and transportation assets connect to other pipelines or facilities owned and operated by unaffiliated third parties. The continuing operation of, and the Partnership's continuing access to, such third-party pipelines, processing facilities and other midstream facilities is not within the Partnership's 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 the Partnership's costs to access and transport on these third-party pipelines significantly increase, the Partnership's 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 the Partnership gathers or transports does not meet the product quality requirements of such pipelines or facilities, the Partnership's operating margin and cash flow could be adversely affected.

The Partnership’s debt levels could limit our flexibility and adversely affect its financial health or limit its flexibility to obtain financing and to pursue other business opportunities.

The Partnership continues to have the ability to incur debt, subject to limitations in its credit facility. The Partnership’s level of indebtedness could have important consequences to it, including the following:

- the Partnership’s 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;
- the Partnership’s funds available for operations, future business opportunities and distributions to unitholders will be reduced by that portion of the Partnership’s cash flows required to make interest payments on its debt;
- the Partnership’s debt level will make it more vulnerable to general adverse economic and industry conditions;
- limit the Partnership’s flexibility in planning for, or reacting to, changes in its business and the industry in which it operates; and
- increase the risk that we may default on our debt obligations.

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

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

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

- incur subsidiary indebtedness;
- engage in transactions with its affiliates;
- consolidate, merge or sell substantially all of its assets;
- incur liens;

- enter into sale and lease back transactions; and
- change business activities it conducts.

In addition, the Partnership's credit facility requires it to satisfy and maintain a specified financial ratio. The Partnership's ability to meet that financial ratio can be affected by events beyond its control, and the Partnership cannot assure you that it will continue to meet that ratio.

The Partnership's ability to comply with the covenants and restrictions contained in its credit facility and indentures may be affected by events beyond its control, including prevailing economic, financial and industry conditions. If market or other economic conditions deteriorate, the Partnership's ability to comply with these covenants may be impaired. A breach of any of these covenants could result in an event of default under its 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 the Partnership's credit facility or indentures is accelerated, there can be no assurance that it 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 the Partnership's ability to finance future operations or capital needs or to engage in other business activities.

Increases in interest rates could adversely impact the price of the Partnership's common units, its ability to issue equity or incur debt for acquisitions or other purposes and its ability to make cash distributions at its intended levels.

Interest rates on future credit facilities and debt offerings could be higher than current levels, causing the Partnership's financing costs to increase accordingly. As with other yield-oriented securities, the Partnership's unit price is impacted by its 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 the Partnership's units, and a rising interest rate environment could have an adverse impact on the price of its common units, its ability to issue equity or incur debt for acquisitions or other purposes and its ability to make cash distributions at its intended levels.

The Partnership is vulnerable to operational, regulatory and other risks due to its significant assets in south Louisiana and the Gulf of Mexico, including the effects of adverse weather conditions such as hurricanes.

The Partnership's operations and revenues will be significantly impacted by conditions in south Louisiana and the Gulf of Mexico because the Partnership significant assets located in these two areas. The Partnership's concentration of activity in Louisiana and the Gulf of Mexico makes the Partnership more vulnerable than many of its 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 the Partnership's operations could experience the same condition at the same time, these conditions could have a relatively greater impact on the Partnership's 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 the Partnership's results of operations and financial condition.

The NGL products the Partnership produces has 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 the Partnership handles or reduce the fees the Partnership charges for its services. The Partnership's 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 the Partnership has experienced in greater volumes recently, 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 the Partnership's 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 the Partnership provides as well as NGL prices, which would negatively impact our results of operations and financial condition.

The Partnership expects to encounter significant competition in any new geographic areas into which it seeks to expand, and the Partnership's ability to enter such markets may be limited.

If the Partnership expands its operations into new geographic areas, the Partnership expects 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 the Partnership, 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, the Partnership may not be able to successfully develop acquired assets and markets located in new geographic areas and its results of operations could be adversely affected.

The Partnership does not own most of the land on which its pipelines and compression facilities are located, which could disrupt its operations.

The Partnership does not own most of the land on which its pipelines and compression facilities are located, and it is therefore subject to the possibility of more onerous terms and/or increased costs to retain necessary land use if it does not have valid rights-of-way or leases or if such rights-of-way or leases lapse or terminate. The Partnership sometimes obtains the rights to land owned by third parties and governmental agencies for a specific period of time. The Partnership's loss of these rights, through its inability to renew right-of-way contracts, leases or otherwise, could cause it to cease operations on the affected land, increase costs related to continuing operations elsewhere and reduce its revenue.

The Partnership offers pipeline, truck, rail and barge services. Significant delays, inclement weather or increased costs affecting these transportation methods could materially affect the Partnership's operations and earnings.

The Partnership offers pipeline, truck, rail and barge services. The costs of conducting these services could be negatively affected by factors outside of the Partnership's 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 the Partnership's 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.

The Partnership 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 the Partnership's results of operations. In the event that accidents occur, the Partnership may be unable to obtain desired contractual indemnities, and its 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 the Partnership's costs and negatively impact its results of operations.

The Partnership's trucking services are subject to regulation as motor carriers by the United States Department of Transportation ("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 the Partnership's 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 the Partnership's 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 the Partnership does not make acquisitions on economically acceptable terms or efficiently and effectively integrate the acquired assets with its asset base, its future growth will be limited.

The Partnership's ability to grow depends, in part, on its ability to make acquisitions that result in an increase in cash generated from operations on a per unit basis. If the Partnership is unable to make accretive acquisitions either because it is (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 its future growth and ability to increase distributions will be limited.

From time to time, the Partnership may evaluate and seek to acquire assets or businesses that it believes complement its existing business and related assets. The Partnership may acquire assets or businesses that it plans to use in a manner materially different from its 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 the Partnership's 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 the Partnership's operations and cash flows. If the Partnership consummates any future acquisition, its 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 the Partnership will consider in determining the application of these funds and other resources.

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

The renewal or replacement of existing contracts with the Partnership customers at rates sufficient to maintain current revenues and cash flows depends on a number of factors beyond the Partnership's 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 it serves. The inability of the Partnership's management to renew or replace the Partnership's current contracts as they expire and to respond appropriately to changing market conditions could have a negative effect on the Partnership's profitability.

In particular, the Partnership's ability to renew or replace its existing contracts with industrial end-users and utilities impacts our profitability. For the year ended December 31, 2015, approximately 50.4% of the Partnership's sales of gas transported using the Partnership's 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 the Partnership in marketing natural gas, the Partnership often competes in the end-user and utilities markets primarily on the basis of price.

The Partnership is exposed to the credit risk of its customers and counterparties, and a general increase in the nonpayment and nonperformance by its customers could have an adverse effect on its financial condition and results of operations.

Risks of nonpayment and nonperformance by the Partnership's customers are a major concern in its business. The Partnership is subject to risks of loss resulting from nonpayment or nonperformance by its customers and other counterparties, such as its lenders and hedging counterparties. Any increase in the nonpayment and nonperformance by the Partnership's customers could adversely affect its results of operations and reduce its ability to make distributions to us. Additionally, many of the Partnership's 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 the Partnership's customers' liquidity and ability to make payment or perform on its obligations to the Partnership. Furthermore, some of the Partnership's 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 the Partnership.

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 the Partnership's customers, which could adversely impact its revenues.

A portion of the Partnership's 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 the Partnership's customers and could directly affect the Partnership's 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 the Partnership's suppliers and customers that could reduce the volumes of natural gas that move through the

Partnership's gathering systems which could materially adversely affect its revenue and results of operations.
Transportation on certain of the Partnership's natural gas pipelines is subject to federal and state rate and service regulation, which could limit the revenues the Partnership collects from its customers and adversely affect the cash available for distribution to us. The imposition of regulation on the Partnership's currently unregulated natural gas pipelines also could increase its operating costs and adversely affect the cash available for distribution to us.
The rates, terms and conditions of service under which the Partnership transports natural gas in its pipeline systems in interstate commerce are subject to regulation of 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 the Partnership's 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 the Partnership could have a material adverse effect on its business, financial condition, results of operations, and cash available for distribution. Under the NGPA, the Partnership is required to justify its rates for interstate transportation service on a cost-of-service basis every five years. The Partnership's 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 the Partnership's rates for Section 311 transportation service or intrastate transportation service should be lowered, the Partnership's business could be adversely affected.

The Partnership's 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 the Partnership's 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. The Partnership's 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 the Partnership's operations, but the industry could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes.

If the Partnership fails to comply with all applicable FERC-administered statutes, rules, regulations and orders, it 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 the Partnership's business. The Partnership is subject to some ratable take and common purchaser statutes in the states where it operates. 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 the Partnership's rights as owners of gathering facilities to decide with whom the Partnership 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 the Partnership operates 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 the Partnership’s liquids pipelines is subject to federal rate and state and service regulation, which could limit the revenues the Partnership collects from its customers and adversely affect the cash available for distribution to us.

The Partnership’s 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 the Partnership's ability to set rates based on its costs or could order the Partnership to reduce its 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 the Partnership's terms and conditions of service if it determines that they are unjust and unreasonable or unduly discriminatory or preferential.

As the Partnership acquires, constructs and operates new liquids assets and expands its liquids transportation business, the classification and regulation of its liquids transportation services are subject to ongoing assessment and change based on the services it provides and determinations by FERC and the courts. Such changes may subject additional services we provide to regulation by FERC, which could increase the Partnership's operating costs, decrease its rates and adversely affect its business.

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

The states in which the Partnership conducts 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 the Partnership's gathering facilities are not regulated under that statute. The gathering line exemptions, however, may be revised in the future and place more of the Partnership's gathering facilities under jurisdiction of the DOT. Nonetheless, the Partnership's 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, the Partnership's 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. The Partnership's costs relating to compliance with the required testing under the TRRC regulations were approximately at \$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 the Partnership's pipelines fail to meet the safety standards mandated by the TRRC or the DOT regulations, then it 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, the Partnership's liquids transportation pipelines are subject to regulation by the DOT, through the 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 the PHMSA or state requirements will not have a material adverse effect on our results of operations or financial positions. As the Partnership's operations continue to expand into and around urban or more populated areas, such as the Barnett Shale, the Partnership may incur additional expenses to mitigate noise, odor and light that may be emitted in its operations and expenses related to the appearance of its facilities. Municipal and other local or state regulations are imposing various obligations including, among other things, regulating the location of Partnership facilities, imposing limitations on the noise levels of its facilities and requiring certain other improvements that increase the cost of our facilities. The Partnership is also subject to claims by neighboring landowners for nuisance related to the construction and operation of the Partnership's facilities, which could subject it to damages for declines in neighboring property values due to its 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 the Partnership 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 the Partnership's facilities and the cleanup of hazardous substances and other wastes that may have been released at properties currently or previously owned or operated by the Partnership or locations to which it has 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 the Partnership's facilities or upon or through which its 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 the Partnership's business due to its handling of natural gas, crude oil and other petroleum substances, the Partnership’s brine disposal operations, air emissions related to the Partnership's operations, historical industry operations, waste disposal practices and the prior use of natural gas flow meters containing mercury. For example, the Partnership operates 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. The Partnership may incur material environmental costs and liabilities. Furthermore, the Partnership's insurance may not provide sufficient coverage in the event an environmental claim is made against it.
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 the Partnership’s brine disposal operations.
The Partnership's business may be adversely affected by increased costs due to stricter pollution control requirements or liabilities resulting from non-compliance with required operating or other regulatory permits. New environmental laws or regulations, including, for example, legislation relating to the control of greenhouse gas emissions, or changes in existing environmental laws or regulations might adversely affect the Partnership's operations, including its processing, storage or transportation activities, as well as, waste management or air emissions might adversely affect its business and its profitability. Federal and state agencies could also impose additional safety requirements, any of which could affect the Partnership's profitability.
Recent rules under the Clean Air Act imposing more stringent requirements on the oil and gas industry could cause the Partnership and its customers to incur increased capital expenditures and operating costs as well as reduce the demand for the Partnership's 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 the Partnership's assets and operations and could require additional modifications both to its and to its 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 the Partnership's suppliers and customers could result in reduced production by those suppliers and customers and thus translate into reduced demand for the Partnership's 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. The

Partnership 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 the Partnership provides.

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, the Partnership's equipment and operations could require the Partnership to incur additional costs to reduce emissions of GHGs associated with its operations, could adversely affect its 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 the Partnership gathers, processes or otherwise handles in connection with its 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, the Partnership may be obligated to develop and implement plans to avoid potential adverse impacts to protected species, and it may be prohibited from conducting operations in certain locations or during certain seasons, such as breeding and nesting seasons, when its 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 the Partnership's 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.

The Partnership's 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 the Partnership's operations and financial condition.

The Partnership’s 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 the Partnership's related operations. The Partnership is not fully insured against all risks incident to its business. In accordance with typical industry practice, the Partnership has appropriate levels of business interruption and property insurance on its underground pipeline systems. The Partnership is 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 the Partnership's 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 the Partnership's 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 the Partnership 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 its 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 the Partnership encounters, reduce the Partnership's ability to monetize or restructure the Partnership's existing derivative contracts, and increase the Partnership's exposure to less creditworthy counterparties. If the Partnership reduces its use of derivatives as a result of the legislation and regulations, the Partnership's results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect the Partnership's ability to plan for and fund capital expenditures and to generate sufficient cash flow to pay quarterly distributions at current levels or at all. The Partnership's 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 the Partnership, its financial condition and its results of operations.

The Partnership's use of derivative financial instruments does not eliminate its 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 its income.

The Partnership's operations expose us to fluctuations in commodity prices, and the Partnership's credit facility exposes it to fluctuations in interest rates. The Partnership uses over-the-counter price and basis swaps with other natural gas merchants and financial institutions. Use of these instruments is intended to reduce the Partnership's exposure to short-term volatility in commodity prices. As of December 31, 2015, the Partnership had hedged only portions of its expected exposures to commodity price risk. In addition, to the extent the Partnership hedges it commodity price risk using swap instruments, the Partnership will forego the benefits of favorable changes in commodity prices. Although the Partnership does not currently have any financial instruments to eliminate its exposure to interest rate fluctuations, we may use financial instruments in the future to offset its exposure to interest rate fluctuations.

Even though monitored by management, the Partnership's hedging activities may fail to protect it and could reduce its earnings and cash flow. The Partnership's 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;
- the Partnership's 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 the Partnership seeks protection. For example:
- the duration of a hedge may not match the duration of the risk against which the Partnership seeks protection;
- variations in the index the Partnership uses to price a commodity hedge may not adequately correlate with variations in the index the Partnership uses to sell the physical commodity (known as basis risk); and

the Partnership may not produce or process sufficient volumes to cover swap arrangements the Partnership enters into for a given period. If the Partnership's actual volumes are lower than the volumes the Partnership estimated when entering into a swap for the period, it might be forced to satisfy all or a portion of its derivative obligation without the benefit of cash flow from the sale or purchase of the underlying physical commodity, which could adversely affect the Partnership's 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.

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 the Partnership's business and results of operations adversely impact its results of operations.

Gathering and compression services require laborers skilled in multiple disciplines, such as equipment operators, mechanics and engineers, among others. The Partnership's business is dependent on its 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. The Partnership's 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 the Partnership's ability to manage and operate its business. If the Partnership is unable to successfully attract and retain an appropriately qualified workforce, its results of operations could be negatively affected.

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

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

The Partnership's assets were constructed over many decades which may cause its 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 the Partnership's pipelines that could have a material adverse effect on its business and results of operations.

The Partnership's 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 the Partnership's results of operations, financial position or cash flows, as well as its ability to make cash distributions to its unitholders.

The Partnership's success depends on key members of its management, the loss or replacement of whom could disrupt its business operations.

The Partnership depends on the continued employment and performance of the officers of the General Partner and key operational personnel. The General Partner has entered into employment agreements with each of its executive officers. If any of these officers or other key personnel resign or become unable to continue in their present roles and are not adequately replaced, the Partnership's business operations could be materially adversely affected. The Partnership does not maintain any “key man” life insurance for any officers.

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 the Partnership's 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. The Partnership has 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 the Partnership's pipelines were built was purchased in fee. The Partnership's processing plants are located on land that the Partnership leases or owns in fee.

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

Item 3. Legal Proceedings

Our operations and those of the Partnership are subject to a variety of risks and disputes normally incident to our business. As a result, at any given time we or the Partnership 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. Additionally, the Partnership 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 and the Partnership maintain insurance policies with insurers in amounts and with coverage and deductibles as our Managing Member and the General Partner believe are reasonable and prudent. However, we cannot assure you that this insurance will be adequate to protect us and the Partnership 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, the Partnership’s subsidiaries acquire pipeline easements and other property rights by exercising rights of eminent domain and common carrier. As a result, from time to time the Partnership (or its subsidiaries) is a party to a number of lawsuits under which a court will determine the value of pipeline easements or other property interests obtained by the Partnership’s 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, the Partnership does not expect that awards in these matters will have a material adverse impact on its consolidated results of operations, financial condition, or cash flows.

The Partnership (or its subsidiaries) is defending lawsuits filed by owners of property located near processing facilities or compression facilities constructed by the Partnership as part of its 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. The Partnership's 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. The Partnership intends to continue vigorously defending the case. The success of the plaintiffs' appeal as well as the Partnership's costs and legal exposure, if any, related to the lawsuit are not currently determinable.

The Partnership owns and operates 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. The Partnership is seeking to recover its losses from responsible parties. The Partnership has 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. The Partnership has 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. The Partnership also filed a claim with its insurers, which the Partnership's insurers denied. The Partnership disputed the denial and intends to proceed with litigation against its insurers. In August 2014, the Partnership 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. The Partnership cannot give assurance that the Partnership will be able to fully recover its losses through insurance recovery or claims against responsible parties.

In June 2014, a group of landowners in Assumption Parish, Louisiana added a subsidiary of the Partnership, 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 the Partnership's costs and legal exposure, if any, related to the lawsuit are not currently determinable. The Partnership intends to vigorously defend the case. The Partnership has also filed a claim for defense and indemnity with its 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 "ENLC". Our common units began trading on March 10, 2014. There was no established public market for our common units prior to March 10, 2014. On February 10, 2016, there were approximately 19,485 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 (i) the high and low closing sales prices per common unit, as reported by the NYSE and (ii) the amount of our quarterly distributions for the periods indicated.

	Range		Cash Distribution
	High	Low	Declared Per Unit
2015:			
Quarter Ended December 31	$23.21	$12.15	$0.255
Quarter Ended September 30	31.03	17.32	0.255
Quarter Ended June 30	35.32	31.09	0.250
Quarter Ended March 31	36.48	30.80	0.245
2014:			
Quarter Ended December 31	$40.86	$30.20	$0.235
Quarter Ended September 30	41.70	36.90	0.230
Quarter Ended June 30	42.18	33.63	0.220
Quarter Ended March 31	36.70	33.34	0.180

We intend to pay distributions to our unitholders on a quarterly basis equal to the cash we receive, if any, from distributions from the Partnership and Tall Oak less reserves for expenses, future distributions and other uses of cash, including:

- federal income taxes, which we are required to pay because we are taxed as a corporation;
- the expenses of being a public company;

- other general and administrative expenses;
- capital contributions to the Partnership upon the issuance by it of additional partnership securities in order to maintain the General Partner's then-current general partner interest, to the extent the GP Board exercises its option to do so;
- capital calls for our interest in Tall Oaks to the extent not covered by our borrowings; and
- cash reserves the Managing Member believes are prudent to maintain.

Our ability to pay distributions is limited by the Delaware Limited Liability Company Act, which provides that a limited liability company may not pay distributions if, after giving effect to the distribution, the company's liabilities would exceed the fair value of its assets. While our ownership of equity interests in the General Partner and the Partnership are included in our calculation of net assets, the value of these assets may decline to a level where our liabilities would exceed the fair value of our assets if we were to pay distributions, thus prohibiting us from paying distributions under Delaware law.

During 2015, the Partnership paid quarterly distributions to its common unitholders in May, August and November of $0.38, $0.385 and $0.39 related to the first, second and third quarters of 2015, respectively. The Partnership paid a quarterly distribution of $0.39 in February 2016 related to the fourth quarter of 2015. Our share of the distributions with respect to our limited and general partner interests in the Partnership totaled $154.4 million for the year ended December 31, 2015.

Performance Graph

The following graph sets forth the cumulative total stockholder return for our common units, the Standard & Poor's 500 Stock Index and a peer group of publicly traded partners of publicly traded limited partnerships in the Midstream natural gas, natural gas liquids, propane, and pipeline industries for the year ended December 31, 2015. The chart assumes that $100 was invested on March 10, 2014, with distributions reinvested. The peer group includes MarkWest Energy Partners, L.P., Energy Transfer Equity, L.P., Plains GP Holdings, L.P., Targa Resources, Inc. and Western Gas Equity Partners, L.P.

Item 6. Selected Financial Data

The historical financial statements included in this report reflect (1) for periods prior to March 7, 2014, the assets, liabilities and operations of Predecessor, the predecessor to Midstream Holdings, which is our historical predecessor and (2) for periods on or after March 7, 2014, the results of our operations, 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 prior to the business combination, including its 38.75% economic interest in 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% economic interest in GCF, were contributed to the Partnership, effective as of March 7, 2014.

The following table presents the selected historical financial and operating data of EnLink Midstream LLC and EnLink Midstream Holdings, LP Predecessor (the "Predecessor"), whose assets comprise the Midstream business, 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 our results or future operations.

	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)	136.9	97.3	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	5,754.0	3,153.5	2,124.6	1,781.5	2,225.9
Operating income (loss)	(1,301.9)	354.3	171.3	126.3	302.1
Other income (expense):					
Interest expense, net of interest income	(103.3)	(49.8)	—	—	—
Income from unconsolidated affiliate investments	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)	(82.1)	(28.2)	14.8	2.0	9.3
Income (loss) from continuing operations before non-controlling interest and income taxes	(1,384.0)	326.1	186.1	128.3	311.4
Income tax provision	(25.7)	(76.4)	(67.0)	(46.2)	(112.1)
Net income (loss) from continuing operations	(1,409.7)	249.7	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)	(1,409.7)	250.7	115.5	75.8	216.1
Less: Net income (loss) from continuing operations attributable to the non-controlling interest	(1,054.5)	126.7	—	—	—
Net income (loss) attributable to EnLink Midstream LLC	$(355.2)	$124.0	$115.5	$75.8	$216.1
Predecessor interest in net income	$—	$35.5	$—	$—	$—
Devon investment interest in net income (loss)	$1.8	$(2.0)	$—	$—	$—
EnLink Midstream LLC interest in net income (loss)	$(357.0)	$90.5	$—	$—	$—
Net income (loss) attributable to EnLink Midstream LLC per common unit:					
Basic and diluted common unit	$(2.17)	$0.55	$—	$—	$—
Distributions declared per common unit	$(2.17)	$0.55	$—	$—	$—

(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.

	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	$9,565.1	$10,206.7	$2,309.8	$2,535.2	$2,305.3
Long-term debt (including current maturities)	$3,089.8	$2,022.5	$—	$—	$—
Members' equity including non-controlling interest	$5,424.9	$7,074.8	$—	$2,002.0	$1,901.2

Non-GAAP Financial Measures

Cash Available for Distribution

We define cash available for distribution as distributions due to us from the Partnership and our interest in the Partnership's adjusted EBITDA (as defined herein), less maintenance capital, our specific general and administrative costs as a separate public reporting entity, the interest costs associated with our debt and current taxes attributable to our earnings. During 2015, we utilized federal net operating loss carryforwards to offset our taxable income generated during 2015. We have $59.8 million of federal net operating loss carryforwards remaining as of December 31, 2015. Historically, we have had net operating losses that eliminated substantially all of our taxable income and thus we have not historically paid significant amounts of income taxes. We anticipate generating net operating losses for tax purposes during 2016, and as a result, do not expect to incur material amounts of federal and state income tax liabilities. In the event we do generate taxable income, federal and state income tax liabilities will reduce the cash available for distribution to our unitholders. Cash available for distribution is a significant performance metric used by us and by external users of our financial statements, such as investors, commercial banks, research analysts and others to compare basic cash flows generated by us to the cash distributions we expect to pay our unitholders. Using this metric, management and external users of our financial statements can quickly compute the coverage ratio of estimated cash flows to planned cash distributions. Cash available for distribution is also an important financial measure for our unitholders since it serves as an indicator of our success in providing a cash return on investment. 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 cash available for distribution is net income. Cash available for distribution should not be considered as an alternative to GAAP net income. Cash available for distribution is not a presentation made in accordance with GAAP and has important limitations as an analytical tool. Investors should not consider cash available for distribution in isolation or as a substitute for analysis of our results as reported under GAAP. Because cash available for distribution excludes some, but not all, items that affect net income and is defined differently by different companies in our industry, our definition of cash available for distribution may not be comparable to similarly titled measures of other companies, thereby diminishing its utility.

The following is a calculation of our cash available for distribution (in millions):

	Year Ended December 31, 2015	2014
Distribution declared by ENLK associated with (1):		
General partner interest	$2.4	$2.2
Incentive distribution rights	47.5	22.6
ENLK common units owned	104.5	24.8
Total share of ENLK distributions declared	$154.4	$49.6
Transferred interest EBITDA (2)	53.7	187.9
Total cash available	$208.1	$237.5
Uses of cash:		
General and administrative expenses	(4.1)	(3.2)
Current income tax (expense) benefit (3)	0.1	(3.5)
Interest expense	(0.8)	(2.2)
Maintenance capital expenditures (4)	(4.0)	(11.0)
Total cash used	$(8.8)	$(19.9)
Cash Available for distribution	$199.3	$217.6

(1) Represents quarterly distributions paid to us on May 14, 2015, August 14, 2015, November 12, 2015 and distributions declared by ENLK and to be paid to ENLC on February 11, 2016.

(2) Represents our interest in Midstream Holdings' adjusted EBITDA prior to the EMH Drop Downs.

(3) Represents our stand-alone current tax expense.

(4) Represents our interest in Midstream Holdings' maintenance capital expenditures prior to the EMH Drop Downs which is netted against the monthly disbursement of Midstream Holdings' adjusted EBITDA per (2) above.

The following table provides a reconciliation our net income from continuing operations to our cash available for distribution (in millions):

	Year Ended December 31, 2015	2014
Net income (loss)	$(1,409.7)	$249.7
Less: Net income attributable to ENLK	1,377.8	(310.5)
Net income (loss) excluding ENLK	$(31.9)	$(60.8)
ENLC's share of distributions from ENLK (1)	154.4	49.6
ENLC deferred income tax expense (2)	26.2	52.1
Maintenance capital expenditures (3)	(4.0)	(11.0)
Transferred interest EBITDA (4)	53.7	187.9
Other items (5)	0.9	(0.2)
Cash available for distribution	$199.3	$217.6

(1) Represents quarterly distributions paid to us on May 14, 2015, August 14, 2015, November 12, 2015 and distributions declared by ENLK and to be paid to us on February 11, 2016.

(2) Represents our stand-alone deferred taxes.

(3) Represents our interest in Midstream Holdings' maintenance capital expenditures prior to the EMH Drop Downs, which is netted against the monthly disbursement of Midstream Holdings' adjusted EBITDA.

(4) Represents our interest in Midstream Holdings' adjusted EBITDA prior to the EMH Drop Downs.

(5) Represents E2's adjusted EBITDA with respect to 2014 and other non-cash items not included in cash available for distributions.

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	(136.9)	(97.3)	(45.1)
Depreciation and amortization	(387.3)	(284.3)	(187.0)
Gain (loss) on sale of property	(1.2)	0.1	—
Impairments	(1,563.4)	—	—
Gain on litigation settlement	—	6.1	—
Operating income (loss)	$(1,301.9)	$354.3	$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.

The historical financial statements included in this report reflect (1) for periods prior to March 7, 2014, the assets, liabilities and operations of the Predecessor, the predecessor to Midstream Holdings, which is the historical predecessor of EnLink Midstream, LLC and (2) for periods on or after March 7, 2014, the results of operations of EnLink Midstream, LLC, 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 prior to the business combination, including its 38.75% economic interest in 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% economic 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 “Company”, 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, LLC, together with its consolidated subsidiaries including the Partnership. All references in this section to the “Partnership” (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 the Operating Partnership and its consolidated subsidiaries. In addition,“TOM Holdings” is sometimes used to refer to EnLink TOM Holdings, LP itself or to EnLink TOM Holdings, LP together with its consolidated subsidiaries. Finally, because TOM Holdings and its subsidiaries are controlled by the Partnership and have similar operations to the Partnership, references to the “Partnership” in this report should also be read to include TOM Holdings when applicable, including general references to the Partnership’s business in the risk factors and otherwise.

Overview

We are a Delaware limited liability company formed in October 2013. Our assets consist of equity interests in EnLink Midstream Partners, LP, a publicly traded limited partnership engaged in the gathering, transmission, processing and marketing of natural gas and natural gas liquids, or NGLs, condensate and crude oil, as well as providing crude oil, condensate and brine services to producers. Our interests in EnLink Midstream Partners, LP, consist of the following as of December 31, 2015:

- 88,528,451 common units representing an aggregate 26.5% limited partner interest in the Partnership; and
- 100.0% ownership interest in EnLink Midstream Partners GP, LLC, the general partner of the Partnership (the “General Partner”), which owns a 0.5% general partner interest and all of the incentive distribution rights in the Partnership.

The Partnership is required by its partnership agreement to distribute all its cash on hand at the end of each quarter, less reserves established by the General Partner in its sole discretion to provide for the proper conduct of the Partnership’s business, or to provide for future distributions.

The incentive distribution rights in the Partnership entitle us to receive an increasing percentage of cash distributed by the Partnership as certain target distribution levels are reached. Specifically, they entitle us to receive 13.0% of all cash distributed in a quarter after each unit has received $0.25 for that quarter, 23.0% of all cash distributed after each unit has received $0.3125 for that quarter and 48.0% of all cash distributed after each unit has received $0.375 for that quarter.

Since we control the General Partner interest in the Partnership, we reflect our ownership interest in the Partnership on a consolidated basis, which means that our financial results are combined with the Partnership’s financial results and the results of our other subsidiaries. Our consolidated results of operations are derived from the results of operations of the Partnership and also include our deferred taxes, interest of non-controlling partners in the Partnership’s net income, interest income (expense) and general and administrative expenses not reflected in the Partnership’s results of operations. Accordingly, the discussion of our financial position and results of operations in this “Management’s Discussion and Analysis of Financial Condition and Results of Operations” primarily reflects the operating activities and results of operations of the Partnership.

The Partnership primarily focuses 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. The Partnership's 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. The Partnership manages and reports its activities primarily according to the nature of activity and geography. The Partnership has five reportable segments: (1) Texas, which includes the Partnership's natural gas gathering, processing and transmission activities in north Texas and the Permian Basin in west Texas; (2) Oklahoma, which includes the Partnership's natural gas gathering, processing and transmission activities in Cana-Woodford and Arkoma-Woodford Shale areas; (3) Louisiana, which includes the Partnership's natural gas pipelines, natural gas processing plants and NGL assets located in Louisiana; (4) Crude and Condensate, which includes the Partnership's Ohio River Valley ("ORV") crude oil, condensate and brine disposal activities in the Utica and Marcellus Shales, its equity interests in E2 Energy Services, LLC, E2 Appalachian Compression, LLC and E2 Ohio Compression, LLC (collectively, "E2"), its crude oil operations in the Permian Basin and its 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 the Partnership's unconsolidated affiliate investments in Howard Energy Partners ("HEP"), in the Eagle Ford Shale, its 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.

The Partnership manages its operations by focusing on gross operating margin because the Partnership's business is generally to gather, process, transport or market natural gas, NGLs, crude oil and condensate using its assets for a fee. The Partnership earns its fees through various contractual arrangements, which include stated fixed-fee contract arrangements or arrangements where the Partnership purchases and resells commodities in connection with providing the related service and earns a net margin for its fees. While the Partnership's transactions vary in form, the essential element of each transaction is the use of its assets to transport a product or provide a processed product to an end-user at the tailgate of the plant, barge terminal or pipeline. The Partnership defines 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 the Partnership's 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. The Partnership reflects revenue as "Product sales" and "Midstream services" on the Consolidated Statements of Operations.

The Partnership's gross operating margins are determined primarily by the volumes of natural gas gathered, transported, purchased and sold through its pipeline systems, processed at its processing facilities, the volumes of NGLs handled at its fractionation facilities, the volumes of crude oil and condensate handled at its crude terminals, the volumes of crude oil and condensate gathered, transported, purchased and sold and the volume of brine disposed and the volume of condensate stabilized. The Partnership generates revenues from seven primary sources:

- transporting natural gas and NGLs on the pipeline systems it owns;
- processing natural gas at its 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.

The Partnership typically gathers or transports gas owned by others through its facilities for a fee. The Partnership also buys 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 transports and resells the natural gas at the same market index. The fixed discount difference to a market index represents the fee for using the Partnership's assets. The Partnership attempts to execute substantially all purchases and sales concurrently, or it enters into a future delivery obligation, thereby establishing the basis for the fee it will receive for each natural gas transaction. The Partnership's gathering and transportation fee related to a percentage of the index price can be adversely affected by declines in the price of natural gas. The Partnership is also party to certain long-term gas sales commitments that it satisfies through supplies purchased under long-term gas purchase agreements. When the Partnership enters into those arrangements, its sales obligations generally match its purchase obligations. However, over time, the supplies that it has under contract may decline due to reduced drilling or other causes and the Partnership 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 the Partnership's purchase/sale transactions, the resale price is generally based on the same index at which the gas was purchased.

On occasion the Partnership has 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 it captures the difference in the indices (also referred to as basis spread), less the transportation expenses from the two areas, as its fee. Changes in the basis spread can increase or decrease margins or potentially result in losses. For example, the Partnership is a party to one contract with a term to 2019 to supply approximately 150,000 MMBtu/d of gas. The Partnership buys gas for this contract on several different production-area indices on its North Texas Pipeline and sells the gas into a different market area index. The Partnership realizes 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 cash losses on this contract, and greater losses on this contract could occur in future periods if these conditions persist or become worse.

The Partnership typically transports and fractionates or stores NGLs owned by others for a fee based on the volume of NGLs transported and fractionated or stored. The Partnership also buys mixed NGLs from its suppliers at a fixed discount to market indices for the component NGLs with a deduction for its fractionation fee. The Partnership subsequently sells the fractionated NGL products based on the same index-based prices. The operating results of the Partnership's NGL fractionation business are dependent upon the volume of mixed NGLs fractionated and the level of fractionation fees charged. With the Partnership's fractionation business, it also has the opportunity for product upgrades for each of the discrete NGL products. The fees the Partnership earns on the product upgrade from this fractionation business is higher during periods with higher liquids prices.

The Partnership generally gathers or transports crude oil and condensate owned by others by rail, truck, pipeline and barge facilities for a fee. The Partnership also buys crude oil and condensate from a producer at a fixed discount to a market index, then transports and resells the crude oil and condensate at the same market index. The Partnership executes substantially all purchases and sales concurrently, thereby establishing the fee it will receive for each crude oil and condensate transaction. Additionally, the Partnership provides crude oil, condensate and brine services on a volume basis.

The Partnership realizes gross operating margins from its 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 the Partnership's 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 or liquids produced with margins higher during periods of higher natural gas and liquids prices. Under fixed-fee based contracts the Partnership’s 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.

Devon Energy Transaction and EMH Drop Downs

On March 7, 2014, we consummated the transactions contemplated by the Agreement and Plan of Merger, dated as of October 21, 2013 (the “Merger Agreement”), among EnLink Midstream, Inc. (“EMI”), Devon, Acacia Natural Gas Corp I, Inc., formerly a wholly-owned subsidiary of Devon (“Acacia”), and certain other wholly-owned subsidiaries of Devon pursuant to which EMI and Acacia each became our wholly-owned subsidiaries. Upon completion of the merger with Acacia, we indirectly owned a 50% limited partner interest in Midstream Holdings. Also on March 7, 2014, the Partnership consummated the transactions contemplated by the Contribution Agreement, dated as of October 21, 2013, among the Partnership, EnLink Midstream Operating, Devon and certain of Devon’s wholly-owned subsidiaries.

On February 17, 2015, Acacia contributed a 25% interest in Midstream Holdings (the “February Transferred Interests”) to the Partnership in a drop down transaction (the “February EMH Drop Down”) in exchange for 31.6 million units in the Partnership, representing an approximate 9.5% limited partner interest in the Partnership as of December 31, 2015.

On May 27, 2015, Acacia contributed the remaining 25% limited partner interest in Midstream Holdings (the “May Transferred Interests”) to the Partnership 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 36.6 million units in the Partnership, representing an approximate 11.0% limited partner interest in the Partnership as of December 31, 2015. After giving effect to the EMH Drop-Downs, the Partnership owns 100% of Midstream Holdings.

Recent Growth Developments

Acquisitions

Tall Oak. On January 7, 2016, we and Partnership acquired a 16% and 84% 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 the Partnership, a portion of which was derived from the proceeds from the issuance of the Preferred Units (as defined under “Issuance of Preferred Units” below), and (b) (i) 15,564,009 of our common units issued directly by us and (ii) approximately $19.5 million in cash contributed by us.

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 and the Partnership 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 Plant 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, the Partnership 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, the Partnership and Apache jointly funded the development of a new-build processing facility in which each company held a 50-percent undivided ownership interest. The Partnership managed the plant's initial construction and has 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 the Partnership's net processing capacity in the Permian Basin to 343 MMcf/d.

Acquisition of Natural Gas Gathering and Processing Assets. On October 1, 2015, the Partnership 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 predominantly 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, the Partnership 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 Class C common units in the Partnership. 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.

The Partnership 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 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, the Partnership 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, the Partnership plans to make contributions to HEP, primarily to fund its 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, the Partnership 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 of 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, the Partnership constructed three natural gas compression and condensate stabilization facilities during late 2014 and 2015 in Harrison, Monroe and Guernsey counties in Ohio. The Partnership will begin construction on the fourth facility as needed based on available volumes.

Marathon Petroleum Joint Venture. The Partnership has 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 the Partnership's existing Riverside fractionation and terminal complex to Marathon Petroleum's Garyville refinery located on the Mississippi River. This bolt-on project to the Partnership's Cajun-Sibon NGL system is supported by long-term, fee-based contracts with Marathon Petroleum. Under the arrangement, the Partnership 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, Acacia contributed the Transferred Interests to the Partnership through the consummation of the EMH Drop Downs. See “Devon Energy Transaction and EMH Drop Downs” above.

VEX Pipeline. On April 1, 2015, the Partnership 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. The Partnership 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 Partnership’s 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 the Partnership's Common Units

Equity Distribution Agreement. In November 2014, the Partnership 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 the Partnership’s common units from time to time through an “at the market” equity offering program. The Partnership 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. The Partnership has 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 the Partnership 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). The Partnership 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.

Private Placement of Common Units. On October 29, 2015, the Partnership issued 2,849,100 common units with an offering price of $17.55 per common unit to our subsidiary for aggregate consideration of approximately $50.0 million in a private placement transaction, which the Partnership used for general partnership purposes.

Issuance of Preferred Units. On January 7, 2016, the Partnership issued an aggregate of 50,000,000 Series B Cumulative Convertible Preferred Units representing limited partner interests, (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 the Tall Oak acquisition.

The Preferred Units are convertible into the Partnership's 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 the Partnership's 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 the General Partner or the Managing Member, 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, 2015, 2014 and 2013 may not be comparable for the following reasons:

- In connection with the business combination, the Partnership entered into new agreements with Devon that were effective on March 1, 2014 pursuant to which the Partnership provides services to Devon under fixed-fee arrangements in which the Partnership does not take title to the natural gas gathered or processed or the NGLs it fractionates. 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 ended December 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.

	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 the Partnership 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 the Partnership's 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 the Partnership's 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 Partnership operations. The Partnership did not have any legacy operations in Oklahoma.

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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 the Partnership's 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 the Partnership's Texas assets. In addition, increases were further mitigated by a $11.9 million decrease in gross operating margin related primarily to volume declines in the Partnership's Louisiana gas business. The Partnership also had a $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 the Partnership's 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 the Partnership's 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 $136.9 million for the year ended December 31, 2015 compared to $97.3 million for the year ended December 31, 2014, an increase of $39.6 million, or 40.7%. 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 Partnership's Tall Oak, Matador, LPC, and Coronado asset acquisitions, as well as the VEX dropdown;
- the Partnership's unit-based compensation expense increased $3.2 million;
- the Partnership's bad debt expense increased $2.3 million; and
- the Partnership's 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 asset 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. The Partnership recognized an impairment on goodwill of $1,328.2 million related to its Louisiana, Texas, and Crude and Condensate segments and an impairment on intangible assets in its Crude and Condensate segment of $223.1 million during 2015. The Partnership 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. The Partnership 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 its claims against Texas Brine and its insurers. Additional claims related to this matter remain outstanding.

Interest Expense. Interest expense was $103.3 million for the year ended December 31, 2015 compared to $49.8 million for the year ended December 31, 2014, an increase of $53.5 million, or 107.4%. 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):

	Years Ended December 31,	
	2015	2014
Senior notes	$106.0	$55.6
Partnership credit facility	7.9	5.8
Credit facility	0.6	2.2
Capitalized interest	(7.7)	(11.5)
Amortization of debt issue costs and net discount (premium)	0.4	(1.0)
Cash settlements on interest rate swap	(3.6)	(3.6)
Mandatory redeemable non-controlling interest	(1.8)	—
Other	1.5	2.3
Total	$103.3	$49.8

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 the Partnership's investment in HEP due to acquisition activity that occurred in 2015. This increase is partially offset by a decrease in the Partnership's investment in GCF of $4.1 million due to lower throughput volume and decreased product price spreads.

Income Tax Expense. Income tax expense was $25.7 million for the year ended December 31, 2015 as compared to income tax expense of $76.4 million for the year ended December 31, 2014, a decrease of $50.7 million. The decrease in income tax expense is primarily attributable to a decrease in taxable income between periods. Although we realized a loss from continuing operations before income taxes for the year ended December 31, 2015, we did not realize a tax benefit associated with this loss because substantially all of the loss was the result of a goodwill impairment which is treated as a permanent difference for tax. See Note 7 to the consolidated financial statements titled “Income Taxes” for further details.

Net Income (Loss) Attributable to Non-controlling Interest. Net loss attributable to non-controlling interest was $1,054.5 million for the year ended December 31, 2015 as compared to net income of $126.7 million for the year ended December 31, 2014 , a decrease of $1,181.2 million. Net income (loss) attributable to non-controlling interests decreased due to a net loss in 2015 at the Partnership primarily driven by impairment expense offset by higher incentive right distributions received.

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 $97.3 million for the year ended December 31, 2014 compared to $45.1 million for the year ended December 31, 2013, an increase of $52.2 million, or 115.7%.

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 $49.8 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 the Partnership's investment in GCF due to an improvement in turnaround downtime experience as compared to the 2013 period.

Income Tax Expense. Income tax expense was $76.4 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, an increase of $9.4 million. This increase primarily relates to an increase in taxable income related to the Predecessor. During 2013, effective income tax rate was 36%. These rates differed from the U.S. statutory income tax rate due to the effect of state income taxes.

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 hedging activities are recognized currently in earnings as gain on derivatives.

Impairment of Long-Lived Assets. In accordance with FASB ASC 360-10-05, the Partnership evaluates 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 the Partnership's long-lived assets has occurred, the Partnership must estimate the undiscounted cash flows attributable to the asset. The Partnership's 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 the Partnership markets are located;
- the availability and prices of natural gas, NGLs, crude oil and condensate supply;
- the Partnership's 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;
- the Partnership's 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 the Partnership's cash flows, which could require it to record an impairment of an asset.

During 2015, the Partnership reviewed its 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 the Partnership's assets groups in the Crude and Condensate segment were not in excess of its related carrying value. The Partnership 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 the Partnership's Crude and Condensate segment. The non-cash impairment charge is included in the impairment expense line item of the

Consolidated Statement of Operations. The Partnership utilized Level 3 fair value measurements in its impairment analysis of this definite-lived intangible asset, which included discounted cash flow assumptions by management consistent with those utilized in its goodwill impairment analysis.
Additionally, during December 2015, the Partnership recognized a $12.1 million impairment on property, plant and equipment, primarily related to costs associated with the cancellation of various capital projects in its 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 the Partnership's unit price caused a change in circumstances warranting an interim impairment test at the Partnership level. We also performed an annual impairment analysis for both the Company and the Partnership 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 prices during the fourth quarter of 2015.

We and the Partnership perform our goodwill assessments at the reporting unit level. The Partnership uses 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 forecasts and price and estimated operating and general and administrative costs. In estimating cash flows, the Partnership incorporates current and historical market information, among other factors. As of December 31, 2015, we also have $1,426.9 million of goodwill related to our investment in the Partnership that is included in our Corporate segment. We utilize the publicly traded market value of our common units, adjusted for our estimated control premium, in our Corporate level goodwill assessment.

Using the fair value approaches described above, in step one of the goodwill impairment test, the Partnership determined that the estimated fair value of its 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 its 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 the Partnership's Louisiana reporting unit was fully impaired. The Partnership concluded that the fair value of goodwill of its Oklahoma reporting unit substantially exceeded its carrying value as of December 31, 2015, and the entire amount of goodwill disclosed on the Consolidated Balance Sheet associated with this segment is recoverable. We concluded that the fair value of goodwill in our Corporate reporting unit substantially exceeded its carrying value as of December 31, 2015. However, the fair values of the Partnership's 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 the Partnership's Texas reporting unit exceeded its carrying value by 7.4 percent, and the fair value of the Partnership's Crude and Condensate reporting unit approximates its carrying value. As of December 31, 2015, the Partnership had $703.5 million and $93.2 million of goodwill allocated to the Texas and Crude and Condensate reporting units, respectively.

The Partnership's 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 the Partnership's assumptions and estimates, or its assumptions and estimates change due to new information, the Partnership 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 the Partnership's estimates of future operating results and the Partnership's unit price, which could result in future goodwill impairment charges for the Partnership's Texas and Crude and Condensate reporting units due to the potential impact on the cash flows of its operations. Due to further declines in both commodity prices and the Partnership's unit price subsequent to December 31, 2015, it is likely that the Partnership will have a goodwill impairment in both its Texas and Crude and Condensate segments during the first quarter of 2016. In addition, future decreases to our unit price could result in an impairment charge for our Corporate reporting unit.

Commodity Price Risk

The Partnership is subject to significant risks due to fluctuation in commodity prices. The Partnership's exposure to these risks is primarily in the gas processing component of its 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 the Partnership's processed gas arrangements, based on gross operating margin, were processed under POL and POP contracts. A portion of the volume of inlet gas at the Partnership's south Louisiana and north Texas processing plants is settled under POL agreements. Under these contracts the Partnership receives 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 the Partnership's Coronado plants in the Permian Basin are POP based contracts. Under these contracts, the Partnership receives a fee as a portion of the proceeds of the sale of natural gas and liquids. Accordingly, the Partnership's revenues under these contracts are directly impacted by the market price of natural gas and NGLs.

The Partnership also realizes processing gross operating margin under margin contracts. For the year ended December 31, 2015, approximately 0.7% of the Partnership's processed gas arrangements, based on gross operating margin, was processed under margin contracts. The Partnership has a number of margin contracts on its Plaquemine and Pelican processing plants. Under this type of contract, the Partnership pays the producer for the full amount of inlet gas to the plant and it makes a margin based on the difference between the value of liquids recovered from the processed natural gas as compared to the value of the natural gas shrink and the cost of fuel used in processing. The shrink and fuel losses are referred to as plant thermal reduction or PTR.

The Partnership is 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 its assets and on its margins for transportation between certain market centers. Low prices for these products could reduce the demand for the Partnership's services and volumes on its systems.

The prices of crude oil, condensate, 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. The Partnership expects 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 the Partnership's profitability by influencing drilling activity and well operations, and thus the volume of gas, NGLs, condensate and crude oil it gathers and processes. The volatility in commodity prices may cause the Partnership's gross operating margin and cash flows to vary widely from period to period. The Partnership's hedging strategies may not be sufficient to offset price volatility risk and, in any event, do not cover all of its throughput volumes. For a discussion of the Partnership's 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 $628.4 million, $458.9 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	$609.0	$582.9	$338.2
Changes in working capital	19.4	(124.0)	(7.9)
Total	$628.4	$458.9	$330.3

The primary reason for the increase in cash flows before working capital of $26.1 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 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 is 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 $244.7 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, $1,148.6 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	357.9	—
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	$1,148.6	$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 the Partnership's 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 the Partnership's 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 the Partnership's 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 the Partnership's 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 the Partnership's Bridgeport and Cana facilities in its Texas and Oklahoma segments.

Acquisition expenditures increased $166.3 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 $418.5 million and $758.1 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) under the Partnership's credit facility	$176.8	$(140.0)
Net repayments on the Company's credit facility	—	(75.1)
Net repayments on E2 credit facility	—	(13.8)
Partnership's senior unsecured notes borrowings	893.3	1,600.7
Redemption of the Partnership's 2018 notes	—	(760.3)
Partial redemption of the Partnership's 2022 notes	—	(36.4)
Net repayments under capital lease obligations	(3.6)	(3.0)
Debt refinancing costs	(9.6)	(19.7)
Proceeds from issuance of Partnership units	24.4	412.0

Distributions to unitholders, Devon and non-controlling partners in the Partnership are also primary uses of cash in financing activities. Total cash distributions made during the years ended December 31, 2015 and 2014 were as follows (in millions):

	Year Ended December 31,	
	2015	2014
Distributions to members	$162.8	$89.0
Non-controlling partner distributions	359.5	204.3
Distributions to Devon for net assets acquired	166.7	—

The Partnership received contributions from Devon of $27.8 million for the 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. The Partnership 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 credit facility. The Partnership borrows money under the Partnership's $1.5 billion credit facility to fund checks as they are presented. As of December 31, 2015, the Partnership had approximately $1.1 billion of available borrowing capacity under this facility. Change in drafts payable for the years ended December 31, 2015, 2014 and 2013 were as follows (in millions):

	Year Ended December 31,		
	2015	2014	2013
Increase (decrease) in drafts payable	$(12.7)	$10.2	$—

Uncertainties. The Partnership owns and operates 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. The Partnership is seeking to recover its losses from responsible parties. The Partnership has sued Texas Brine Company, LLC (“Texas Brine”), the operator of a failed cavern in the area, and its insurers seeking recovery for these losses. The Partnership has 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. The Partnership also filed a claim with its insurers, which its insurers denied. The Partnership disputed the denial and sued its insurers, but the Partnership has agreed to stay the matter pending resolution of its claims against Texas Brine and its insurers. In August 2014, the Partnership received a partial settlement with respect to the Texas

Brine claims in the amount of $6.1 million, but additional claims remain outstanding. The Partnership cannot give assurance that it will be able to fully recover its losses through insurance recovery or claims against responsible parties.

In June 2014, a group of landowners in Assumption Parish, Louisiana added the Partnership's 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 the Partnership's costs and legal exposure, if any, related to the lawsuit are not currently determinable. The Partnership intends to vigorously defend the case. The Partnership has also filed a claim for defense and indemnity with its insurers.

Capital Requirements. The Partnership considers a number of factors in determining whether its capital expenditures are growth capital expenditures or maintenance capital expenditures. Growth capital expenditures generally include capital expenditures made for acquisitions or capital improvements that the Partnership expects will increase its 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 its 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.

The Partnership expects to fund its 2016 capital expenditures, excluding Tall Oak acquisition of $1.55 billion and including capital contributions to its unconsolidated affiliate investments, as follows (in millions):

	2016
Growth Capital Expenditures	
Texas segment	$ 120 - 140
Louisiana segment	60 - 70
Oklahoma segment	180 - 210
Crude and Condensate segment	5 - 10
Corporate segment	80 - 140
Total	$ 445 - 570
Maintenance Capital Expenditures	$35.0

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

The Partnership expects to fund the growth capital expenditures from the proceeds of borrowing under the Partnership credit facility discussed below and proceeds from other debt and equity sources. The Partnership expects to fund its 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. The Partnership's ability to pay distributions to its unitholders, and to fund planned capital expenditures and to make acquisitions will depend upon 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 its 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 of December 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
Partnership's bank 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 the Partnership 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 the Partnership's credit facility and the Company's 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 the Partnership's cash obligation for interest expense on its credit facility would be approximately $7.5 million per year. The Company's credit facility had no outstanding borrowing as of December 31, 2015.

Indebtedness

As of December 31, 2015, 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
Credit facility (due 2019)	—	—
The Partnership's 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
The Partnership's 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
The Partnership's 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
The Partnership's 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	—
The Partnership's 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
The Partnership's 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

Our Credit Facility. On March 7, 2014, we entered into a new $250.0 million revolving credit facility, which includes a $125.0 million letter of credit subfacility (the “credit facility”). Our obligations under the credit facility are guaranteed by two of our wholly-owned subsidiaries and secured by first priority liens on (i) 88,528,451 Partnership common units and the 100% membership interest in the General Partner indirectly held by us, (ii) the 100% equity interest in each of our wholly-owned subsidiaries held by us and any additional equity interests subsequently pledged as collateral under the credit facility.

The credit facility will mature on March 7, 2019. The credit facility contains certain financial, operational and legal covenants. The financial covenants are tested on a quarterly basis, based on the rolling four-quarter period that ends on the last day of each fiscal quarter, and include (i) maintaining a maximum consolidated leverage ratio (as defined in the credit facility, but generally computed as the ratio of consolidated funded indebtedness to consolidated earnings before interest, taxes, depreciation, amortization and certain other non-cash charges) of 4.00 to 1.00, provided that the maximum consolidated leverage ratio is 4.50 to 1.00 during an acquisition period (as defined in the credit facility) and (ii) maintaining a minimum consolidated interest coverage ratio (as defined in the credit facility, but generally computed as the ratio of consolidated earnings before interest, taxes, depreciation, amortization and certain other non-cash charges to consolidated interest charges) of 2.50 to 1.00 at all times unless an investment grade event (as defined in the credit facility) occurs.

Borrowings under the credit facility bear interest, at our option, at either 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 depending on our leverage ratio. Upon breach by us of certain covenants governing the credit facility, amounts outstanding under the credit facility, if any, may become due and payable immediately and the liens securing the credit facility could be foreclosed upon. We 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 no borrowings under the credit facility, leaving $250.0 million available for future borrowing based on the borrowing capacity of $250.0 million.

Partnership Credit Facility. On February 20, 2014, the Partnership entered into a $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, the Partnership 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. The Partnership also entered into certain amendments to the Partnership credit facility pursuant to which the Partnership is 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 the Partnership consummates one or more acquisitions in which the aggregate purchase price is $50.0 million or more, the Partnership can elect 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 the Partnership's 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, S&P downgraded us to a BBB- credit rating, and our rating is currently under review by Moody's Investors Service.

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%

If the Partnership breaches certain covenants governing the Partnership credit facility, amounts outstanding under the Partnership credit facility, if any, may become due and payable immediately. The Partnership expects 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 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, the Partnership 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, the Partnership 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, the Partnership redeemed $18.5 million aggregate principal amount of the 2022 Notes for $20.0 million, including accrued interest. On September 20, 2014, the Partnership redeemed an additional $15.5 million aggregate principal amount of the 2022 Notes for $17.0 million, including accrued interest. The Partnership 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, the Partnership 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, the Partnership made a payment of approximately $567.4 million for all such tendered 2018 Notes. Also on March 19, 2014, the Partnership 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. The Partnership 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, the Partnership 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, the Partnership issued an additional $100.0 million aggregate principal amount of its 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 the Partnership’s 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, the Partnership 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 its 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, the Partnership 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, the Partnership 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, the Partnership 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, the Partnership 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, the Partnership 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, the Partnership 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, the Partnership 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, the Partnership 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, the Partnership 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, the Partnership 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, the Partnership 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, the Partnership 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 the Partnership's ability to create or incur certain liens or consolidate, merge or transfer all or substantially all of its 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 the Partnership.

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 the Partnership's customers are a major concern in its business. The Partnership is subject to risks of loss resulting from nonpayment or nonperformance by its customers and other counterparties, such as its lenders and hedging counterparties. Any increase in the nonpayment and nonperformance by the Partnership's customers could adversely affect its results of operations and reduce its ability to make distributions to its 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 the Partnership's existing agreements, the Partnership has and will continue to pass along increased costs to its customers in the form of higher fees.

Environmental

The Partnership's operations are subject to environmental laws and regulations adopted by various governmental authorities in the jurisdictions in which these operations are conducted. The Partnership believes it is in material compliance with all applicable laws and regulations. For a more complete discussion of the environmental laws and regulations that impact the Partnership, see “Item 1. Business—Environmental Matters.”

Contingencies

The Partnership is 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, the Partnership’s subsidiaries acquire pipeline easements and other property rights by exercising rights of eminent domain and common carrier. As a result, from time to time the Partnership (or its subsidiaries) is a party to a number of lawsuits under which a court will determine the value of pipeline easements or other property interests obtained by the Partnership’s 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, the Partnership does not expect that awards in these matters will have a material adverse impact on its consolidated results of operations, financial condition, or cash flows.

The Partnership (or its subsidiaries) is defending lawsuits filed by owners of property located near processing facilities or compression facilities constructed by the Partnership as part of its 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. The Partnership's 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. The Partnership intends to continue vigorously defending the case. The success of the plaintiffs' appeal as well as the Partnership's costs and legal exposure, if any, related to the lawsuit are not currently determinable.

The Partnership owns and operates 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. The Partnership is seeking to recover its losses from responsible parties. The Partnership has sued Texas Brine Company, LLC ("Texas Brine"), 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. The Partnership has 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. The Partnership also filed a claim with its insurers, which the Partnership's insurers denied. The Partnership disputed the denial and intends to proceed with litigation against its insurers. In August 2014, the Partnership 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. The Partnership cannot give assurance that the Partnership will be able to fully recover its losses through insurance recovery or claims against responsible parties.

In June 2014, a group of landowners in Assumption Parish, Louisiana added a subsidiary of the Partnership, 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 the Partnership's costs and legal exposure, if any, related to the lawsuit are not currently determinable. The Partnership intends to vigorously defend the case. The Partnership has also filed a claim for defense and indemnity with its 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," "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

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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, the Partnership 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, the Partnership pays the producer for the full amount of inlet gas to the plant, and makes 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”. The Partnership's 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, the Partnership mitigates its risk of processing natural gas when margins are negative primarily through its ability to bypass processing when it is not profitable for the Partnership, 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, the Partnership receives 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, the Partnership's margins from these contracts are greater during periods of high liquids prices. The Partnership's margins from processing cannot become negative under percent of liquids contracts, but do decline during periods of low NGL prices.
3. Percent of proceeds contracts: Under these contracts, the Partnership receives a fee as a portion of the proceeds of the sale of natural gas and liquids. Therefore, the Partnership's margins from these contracts are greater during periods of high natural gas and liquids prices. The Partnership's 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.

The Partnership's primary commodity risk management objective is to reduce volatility in its cash flows. The Partnership maintains a risk management committee, including members of senior management, which oversees all hedging activity. The Partnership enters 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 its risk management committee.

The Partnership has hedged its exposure to fluctuations in prices for natural gas and NGL volumes produced for its account. The Partnership hedges its exposure based on volumes it considers 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, the Partnership has tailored its hedges to generally match the NGL product composition and the NGL and natural gas delivery points to those of its physical equity volumes. The NGL hedges cover specific NGL products based upon the Partnership's 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 the Partnership's 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 the Partnership faces is the risk of mismatching volumes of gas bought or sold on a monthly price versus volumes bought or sold on a daily price. The Partnership enters 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 the Partnership with short or long positions that must be covered. The Partnership uses financial swaps to mitigate the exposure at the time it is created to maintain a balanced position.

The use of financial instruments may expose the Partnership 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 the Partnership engages in hedging activities, it may be prevented from realizing the benefits of favorable price changes in the physical market. However, the Partnership is 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 net fair value assets 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 had no outstanding borrowings on our variable rate credit facility as of December 31, 2015.

The Partnership is exposed to interest rate risk on its variable rate bank credit facility. At December 31, 2015, the Partnership's credit facility had $414.0 million in outstanding borrowings under this facility. A 1% increase or decrease in interest rates would change its annual interest expense by approximately $4.1 million for the year. The Partnership is not exposed to changes in interest rates with respect to its senior unsecured notes due in 2019, 2022, 2024, 2025, 2044, or 2045 as these are fixed-rate obligations. The estimated fair value of the Partnership's 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 the Partnership's 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 the Partnership's 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-50 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 our management, including our Chief Executive Officer and Chief Financial Officer, 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, our 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 during 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

The following table shows information about the executive officers and board of directors (the “Board”) of EnLink Midstream Manager, LLC, our managing member (the “Managing Member”). Executive officers serve until their successors are elected or appointed.

Name	Age	Position with the Managing Member
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 and Conflicts Committees
James C. Crain**	67	Director and Member of the Audit and Conflicts Committees
Leldon E. Echols**	60	Director and Member of Audit* Committee
Rolf A. Gafvert**	62	Director and Member of the Conflicts and Governance and Compensation* Committees

*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 the Partnership's 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 the Partnership.

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 the Managing Member in March 2014 and the 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 the Managing Member and the General Partner in March 2014. Previously, Mr. Hoppe served as Senior Vice President of Midstream Operations for Devon, which he joined in 2007. Mr. Hoppe has more than 25 years of midstream energy-industry experience, including eight years at Thunder Creek Gas Services, where he most recently served as President. Mr. Hoppe holds a Bachelor of Science degree in civil engineering from the University of Wyoming.

McMillan (Mac) Hummel, Executive Vice President and President of Natural Gas Liquids and Crude, joined the Managing Member and the General Partner in March 2014. Previously, Mr. Hummel served in various positions with The Williams Companies, which he joined in 1985, including Vice President of Commodity Services, Vice President of Natural Gas Liquids and Petchem Services and Vice President of Western Region Gathering and Processing. Mr. Hummel began his career with

Williams' Northwest Pipeline while living in Salt Lake City, Utah. Mr. Hummel also served as Director of Business Development for Williams while living in Calgary, Alberta. Mr. Hummel has been a member of the American Fuel & Petrochemical Manufacturers Petrochemical Committee 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 the Managing Member in March 2014 and the 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 our Senior Leadership Team and leads the company's legal and regulatory functions. Before joining the the 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 the Managing Member in March 2014 and the General Partner in December 2012. Mr. Lamb assumed his current role in November 2014, having previously served as Vice President - Finance. Prior to joining the 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 Managing Member and the General Partner 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 and due to his extensive knowledge of the energy 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 the Managing Member and the General Partner since the 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 the Managing Member and the General

Partner since the 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 the Managing Member and the General Partner since the 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 the Managing Member and the General Partner 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.

James C. Crain joined Crosstex Energy, Inc. as a director in July 2006 and has served as a director of the Managing Member since March 7, 2014. Mr. Crain retired as president of Marsh Operating Company in July 2013, where he worked since 1984 and currently serves as an advisor to Marsh Operating Company and is a private investor. Prior to Marsh, he was a partner at the law firm of Jenkens & Gilchrist. Mr. Crain also serves on the board of Approach Resources, Inc. Mr. Crain served as a director of the General Partner from December 2005 to August 2008. He graduated from the University of Texas at Austin with a B.B.A. degree, a master of professional accounting and a doctor of jurisprudence. Mr. Crain was selected to serve as a director due to his legal background and his experience in the oil and natural gas industry, among other factors.

Leldon E. Echols joined Crosstex Energy, Inc. as a director in January 2008 and has served as a director of the Managing Member since March 2014. Mr. Echols is a private investor. Mr. Echols also currently serves as an independent director of Trinity Industries, Inc. and HollyFrontier Corporation, an independent petroleum refiner and marketer. Mr. Echols brings 30 years of financial and business experience to EnLink Midstream. 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 has also served as a director of the General Partner since January 2008. Mr. Echols was selected to serve as a director due to his accounting and financial experience and service as the Chief Financial Officer for a public company, among other factors.

Rolf A. Gafvert was President, CEO and director of Boardwalk GP, LLP, the general partner of Boardwalk Pipeline Partners, LP from 2007 to 2011. Prior to that, Mr. Gafvert served as Co-President of Boardwalk GP, LLC from 2005 to 2007. Mr. Gafvert served as President of Gulf South Pipeline, which became affiliated with Boardwalk Pipeline Partners, LP in 2005, from 2000 to 2011. Mr. Gafvert was involved in Gulf South and its affiliates from 1993 to 2000, including acting as Managing Director of Koch Energy International, VP of Corporate Development for Koch Energy, Inc. and President of Gulf South. Mr. Gafvert has served as a director of the Managing Member since March 7, 2014. He holds a Master's degree in Agricultural Economics and a Bachelor of Science degree in Psychology from Iowa State University. Mr. Gafvert was selected to serve as a director due to his knowledge of the energy business and his business expertise, among other factors.

"Independent" Directors

Because we are a "controlled company" within the meaning of the NYSE rules, 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. Crain, Echols and Gafvert and Ms. Ricciardello qualify as "independent" in accordance with the published listing requirements of The New York Stock Exchange ("NYSE"). The NYSE independence definition includes a series of objective tests, such as that the director is not an employee of the Company and has not engaged in various types of business dealings with the Company. 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 does not impair their ability to effectively serve on the Audit Committee of the Company.

Board Committees

Our Board established three standing committees in March 2014: the Audit Committee, the Conflicts Committee and Governance and Compensation Committee. Each member of the Audit Committee is an independent director in accordance with the NYSE standards described above. Each of the Board committees has a written charter approved by the Board. Copies of such charters and the Code of Ethics and Governance Guidelines are available to any person, free of charge, on our website at www.enlink.com.

The Audit Committee of our Board is currently comprised of Mr. Echols (chair), Mr. Crain and Ms. Ricciardello. The Audit Committee assists our 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 of our Board is currently comprised of Messrs. Crain (chair) and Gafvert. 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 GP, LLC. Any matters approved by the Conflicts Committee will be conclusively deemed to be fair and reasonable to us, approved by all of our unitholders and not a breach by our Managing Member of any duties owed to us or our unitholders.

The Governance and Compensation Committee is comprised of Messrs. Gafvert (chair) and Hager. The Governance and Compensation Committee reviews matters involving governance, including assessing the effectiveness of current policies, monitoring industry developments, and oversees certain compensation decisions as well as the compensation plans described herein.

Board Meetings and Attendance

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, LLC, 2501 Cedar Springs Rd., Suite 100, Dallas, Texas 75201.

Our Board met 12 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.

Code of Ethics

We adopted a Code of Business Conduct and Ethics (the "Code of Ethics") applicable to all of our employees, officers, and directors, with regard to company-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. The Code of Ethics also incorporates our expectations of our employees that enable us to provide accurate and timely disclosure in our filings with the Securities and Exchange Commission and other public communications. A copy of the Code of Ethics is available to any person, free of charge, at our web site: www.enlink.com. If any substantive amendments are made to the Code of Ethics or if we grant any waiver, including any implicit waiver, from a provision of the Code of Ethics to any of our executive officers and directors, we will disclose the nature of such amendment or waiver on our web site.

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, 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.

Item 11. Executive Compensation

Governance and Compensation Committee Report

The Governance and Compensation Committee has reviewed and discussed with management the following section titled "Compensation Discussion and Analysis." Based upon its review and discussions, the Governance and Compensation Committee has recommended to the Board that the Compensation Discussion and Analysis be included in this Annual Report on Form 10-K.

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. The Managing Member manages our operations and activities, and its officers and the Board make decisions on our behalf. The compensation of the executive officers and directors of the Managing Member is determined by the Board upon the recommendation of its Governance and Compensation Committee. Our named executive officers also serve as named executive officers of EnLink Midstream GP, LLC, our indirect wholly-owned subsidiary and the general partner of the Partnership; therefore, the compensation of our named executive officers reflects total compensation for services to all EnLink entities during the year ended December 31, 2015. We pay 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. We currently pay a monthly fee to the General Partner to cover our portion of administrative and compensation costs, including compensation costs relating to the named executive officers.

Based on information that we tracked regarding the amount of time spent by each of our named executive officers on business matters relating to EnLink Midstream, LLC, 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%
Benjamin D. Lamb	90%	10%

Compensation Philosophy and Principles

Our executive compensation is designed to attract, retain and motivate top-tier executives and align their individual interests with the interests of our unitholders. It is the Governance and 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 Governance and 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 Governance and 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 Governance and 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 the Managing Member. The Governance and Compensation Committee recommends to the Board adjustments to the overall compensation program and to its individual components as the Governance and Compensation Committee determines necessary to achieve our goals. The Governance and Compensation Committee periodically retains consultants to assist in its review and to provide input regarding its compensation program and each of its elements.

Role of Peer Group and Benchmarking

For 2016, the Governance and Compensation Committee and Meridian Compensation Partners, LLC (“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 Governance and Compensation Committee considers the Peer Group companies annually, but historically there have been few changes from year to year. Companies are typically added or removed from the Peer Group as the result of a change in organizational structure or relative size/market capitalization as compared to us.

When evaluating annual compensation levels for each named executive officer, the Governance and 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 Governance and 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 Governance and Compensation Committee relating to all aspects of executive compensation, bonus structure and bonus methodology.

While compensation data from the Peer Group is considered, the Governance and Compensation Committee does not attempt to set compensation components to meet specific benchmarks. The Peer Group data that is reviewed by the Governance and 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 Governance and 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 Governance and 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 Governance and Compensation Committee recommends base salaries for the named executive officers based on the historical salaries for services rendered to us and our 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 year 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 Governance and 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 Governance and Compensation Committee and the Board. The named executive officers are designated as corporate officers, gas business unit officers or liquids business unit officers for purposes of the STI Program. The metrics employed by the STI Program vary depending on the applicable officer's business unit designation. The STI Program contemplates that (i) named executive officers designated as corporate officers will be eligible for bonuses based on our overall achievement level of EBITDA 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 Governance and 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 Governance and 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 Governance and 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 Governance and Compensation Committee, will determine final bonus amounts under the STI Program for the named executive officers. The Governance and Compensation Committee believes that a portion of executive compensation must remain discretionary and subject to the discretion of the Governance and Compensation Committee and the Board with respect to bonus awards payable to its named executive officers. Therefore, the STI Program contemplates that the Governance and Compensation Committee and the Board retain discretion with respect to bonus awards payable to named executive officers. The Governance and 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 Governance and 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 Governance and Compensation Committee as a whole. All of our named executive officers met or exceeded their minimum personal performance objectives for 2015. Accordingly, the Governance and 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 the Managing Member’s officers and directors with the interests of our unitholders. Accordingly, such officers and directors are 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”). In addition, the Managing Member’s officers and directors also are eligible to participate in the EnLink Midstream GP, LLC Long-Term Incentive Plan (the “GP Plan”).

The Board, at the recommendation of the Governance and Compensation Committee, approves the grants of awards to our named executive officers. The Governance and 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 considerations include: the general goal of allowing the named executive officer the opportunity to earn aggregate equity compensation (comprised of our units and Partnership units) in the upper quartile of our Peer Group; the amount of unvested equity held by the individual executive; the executive’s performance; and other factors as determined by the Governance and Compensation Committee.

A discussion of each plan follows:

EnLink Midstream, LLC 2014 Long-Term Incentive 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 determines which eligible individuals receive awards under the 2014 Plan, subject to the Board’s approval of awards of our named executive officers. The 2014 Plan is administered by the Governance and Compensation 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”), distribution equivalent rights (“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 us 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 by the Managing Member as of December 31, 2015. The long-term compensation structure is intended to align the performance of participants with long-term performance for our unitholders.

The 2014 Plan will automatically expire on the tenth anniversary of its effective date. The 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

Governance and Compensation 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 Board or the Governance and Compensation 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 our common units 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 Governance and Compensation Committee determines. The Governance and Compensation 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 on the date of exercise over the grant price of the UAR. UARs will be exercisable on such terms as the Governance and Compensation Committee determines. The Governance and Compensation 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 will 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 subject to a substantial risk of forfeiture, restrictions on transferability and any other restrictions determined by the Governance and Compensation Committee. The Governance and Compensation Committee may provide, in its discretion, that the distributions made by us 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 Governance and Compensation 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 or a combination of cash and common units at the end of a specified period. Restricted incentive units may be subject to restrictions, including a risk of forfeiture, as determined by the Governance and Compensation Committee. The Governance and Compensation 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 a 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 Governance and Compensation Committee.
- Unit Awards. The 2014 Plan permits the grant of unit awards, which are common units 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, or a combination of both, contingent upon the annual attainment of specified performance measures within a specified period. The Governance and Compensation 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 Governance and Compensation 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 Governance and Compensation 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, the Partnership or the General Partner and except as provided in the award agreement, the Governance and 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 of us and except as provided in the award agreement, the Governance and Compensation 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 Governance and Compensation 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 Governance and Compensation 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 Governance and Compensation 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.

EnLink Midstream GP, LLC Long-Term Incentive Plan. EnLink Midstream GP, LLC adopted the GP Plan for employees, consultants and independent contractors of EnLink Midstream GP, LLC and its affiliates and outside directors of the GP Board who perform services for the Partnership. The GP Plan is administered by the compensation committee of the GP Board (the “GP Committee”) and permits the grant of awards, which may be awarded in the form of restricted incentive units or unit options. An aggregate of 9,070,000 common units representing limited partner interests in the Partnership are authorized for issuance under the GP Plan. 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 is intended to align the participant’s performance with long-term performance for the Partnership’s 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 GP 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 GP Board or GP Commitee 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 GP 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 GP Board or the GP 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:

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Unit Options. The GP Plan currently permits the grant of options covering common units of the Partnership. 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 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, the Partnership or the General Partner, 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 the General Partner in the open market, common units already owned by the General Partner, common units acquired by the General Partner directly from us or any other person, or any combination of the foregoing. The 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 the 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 of the Partnership upon the vesting of such restricted incentive units. The GP 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 GP 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, the Partnership or the General Partner. Common units to be delivered upon the vesting of restricted incentive units may be common units acquired by the General Partner in the open market, common units already owned the General Partner, common units acquired by the General Partner directly from us or any other person or any combination of the foregoing. The General Partner will be entitled to reimbursement by the Partnership for the cost incurred in acquiring common units. If the Partnership issues new common units upon vesting of the restricted incentive units, the total number of common units outstanding will increase. The GP Committee, in its discretion, may grant tandem 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 GP 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. The Partnership intends 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 current policy, GP Plan participants will not pay any consideration for the common units they receive, and the Partnership will receive no remuneration for the units.

Performance Unit Awards. In March 2015, the Managing Member and the General Partner granted performance awards under 2014 Plan and the GP 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 the Partnership (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 the Partnership’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 the Partnership, a portion of which are in the form of our performance units and performance units of the Partnership 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, the Managing Member 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 Benjamin D. Lamb, respectively. In addition, for fiscal year 2015, the 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 Benjamin D. 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. We offer 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 our other employees. We maintain 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, we 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. A portion of the retirement benefits provided to the named executive officers were allocated to us as general and administration expenses.

Perquisites. The Managing Member 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, our manager, the Operating Partnership, the Partnership, its general partner, or 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 of directors of the General Partner (the "Partnership Board") or its 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 Partnership Board or its 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 Governance and 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 Governance and Compensation Committee. Barry E. Davis, the Chief Executive Officer, reviews his recommendations regarding the compensation of his leadership team with the Governance and 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 options' remaining vesting period. As a result, we have discontinued grants of unit option awards and instead grant restricted unit and restricted incentive unit awards to the named executive officers and other employees. We have structured the compensation program in a manner intended to comply with Section 409A of the Internal Revenue Code. If an executive is entitled to nonqualified deferred compensation benefits that are subject to Section 409A, and such benefits do not comply with Section 409A, then the benefits are taxable in the first year they are not subject to a substantial risk of forfeiture. In such case, the service provider is subject to regular federal income tax, interest and an additional federal income tax of 20% of the benefit includible in income. 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 Officer	2014	587,885	800,000	6,000,000	—	1,600,000	—	683,607		9,671,492
	2013	525,000	492,188	1,609,522	—	—	—	266,774		2,893,484
Steve J. Hoppe Executive Vice	2015	389,827	300,000	1,570,488	—	—	—	147,699	(5)	2,408,014
President and President of Gathering	2014	304,327	350,000	2,500,000				93,832		3,248,159
McMillan (“Mac”) Hummel Executive Vice	2015	389,538	300,000	1,570,488	—	—	—	203,570	(6)	2,463,596
President and President of Natural Gas Liquids 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	2014	391,923	500,000	3,000,000	—	800,000	—	480,884		5,172,807
President and Chief Financial Officer	2013	350,000	224,100	1,465,519	—	—	—	164,596		2,204,215
Benjamin D. Lamb (9) Senior Vice President	2015	283,904	225,000	1,702,321	—	—	—	92,414	(8)	2,303,639

(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, LLC and 50% in restricted units or restricted incentive units of EnLink Midstream Partners, LP.

(2) The amounts shown represent the grant date fair value of awards computed in accordance with FASB ASC 718. See Note 12 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 or dividends on restricted units and restricted incentive units and performance awards of EnLink Midstream, LLC in the amount of $153,021 in 2015 and distributions on restricted units or restricted incentive units and performance units of EnLink Midstream Partners, LP in the amount $260,108 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 units and restricted incentive units and performance units of EnLink Midstream, LLC in the amount of $43,134 in 2015 and distributions on restricted incentive units and performance units of EnLink Midstream Partners, LP in the amount of $76,952 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 units and restricted incentive units and performance awards of EnLink Midstream, LLC in the amount of $36,406 in 2015 and distributions on restricted incentive units and performance units of EnLink Midstream Partners, LP in the amount of $71,228 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 or dividends on restricted units or restricted incentive units of EnLink Midstream, LLC in the amount of $95,230 in 2015 and distributions on restricted units or restricted incentive units of EnLink Midstream Partners, LP in the amount of $158,809 in 2015.

(8) Amount of all other compensation for Mr. Benjamin 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, dividends or distributions on restricted units or restricted incentive units of EnLink Midstream, LLC in the amount of $22,627 in 2015 and distributions on restricted units or restricted incentive units of EnLink Midstream Partners, LP in the amount of $42,590 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 2014 Plan and the GP Plan.

ENLINK MIDSTREAM, LLC—GRANTS OF PLAN-BASED AWARDS

		Estimated Future Payouts Under Equity Incentive Plan Awards					
Name	Grant Date	Threshold (#)	Target (#)	Maximum (#)	All Other Awards: Number of Units		Grant Date Fair Value of Shares Awards ($)
Barry E. Davis	3/3/2015				11,891	(1)	$400,013
	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
Michael J. Garberding	3/3/2015				7,432	(1)	$250,012
	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
Benjamin D. Lamb	3/5/2015				2,601	(1)	$87,498
	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.

ENLINK MIDSTREAM GP, LLC—GRANTS OF PLAN-BASED AWARDS

Name	Grant Date	Estimated Future Payouts Under Equity Incentive Plan Awards Threshold (#)	Target (#)	Maximum (#)	All Other Unit Awards: Number of Units		Grant Date Fair Value of Unit Awards ($)
	3/3/2015				14,920	(1)	$400,005
Barry E. Davis	3/17/2015				30,680	(2)	$874,994
	3/17/2015	—	30,680	61,360			$812,713
Steve J. Hoppe	3/3/2015						