UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

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

For the fiscal year ended December 31, 2016

OR

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

For the transition period from to

Commission file number: 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	75201
(Address of principal executive offices)	(Zip Code)

(Registrant's telephone number, including area code)

(214) 953-9500

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

Title of Each Class	Name of Exchange on which Registered
Common Units Representing Limited 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 No

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

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

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.

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

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

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

The aggregate market value of the common units representing limited liability company interests held by non-affiliates of the registrant was approximately $1.0 billion on June 30, 2016, based on $15.91 per unit, the closing price of the common units as reported on The New York Stock Exchange on such date.

At February 8, 2017, there were 180,075,376 common units outstanding.

DOCUMENTS INCORPORATED BY REFERENCE:

None.

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ENLINK MIDSTREAM, LLC

PART I

Item 1. Business

General

EnLink Midstream, LLC ("ENLC") 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 5.1% limited partner interest in EnLink Midstream Partners, LP (the "Partnership") as of December 31, 2016 and also owns EnLink Midstream Partners GP, LLC, the general partner of the Partnership (the "General Partner"). At the conclusion of the mergers in March 2014, 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"). As a result of the drop down transactions discussed below, Acacia owned approximately 17.2% of the limited partner interests in the Partnership as of December 31, 2016, bringing ENLC's total ownership, through its wholly-owned subsidiaries, of limited partner interests in the Partnership to 22.3% as of December 31, 2016.

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 2015 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. On May 27, 2015, Acacia contributed the remaining 25% limited partner interest in Midstream Holdings (the "May 2015 Transferred Interests") to the Partnership in a drop down transaction (the "May 2015 EMH Drop Down" and together with the February 2015 EMH Drop Down, the "EMH Drop Downs") in exchange for 36.6 million units in the Partnership. 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. We post the following filings in the "Investors" section of our website as soon as reasonably practicable after they are electronically filed with or furnished to the Securities and Exchange Commission: our annual reports on Form 10-K; our quarterly reports on Form 10-Q; our current reports on Form 8-K; and any amendments to those reports or statements filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended. All such filings on our website are available free of charge.

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

In this report, the terms "Company" or "Registrant" as well as the terms "ENLC," "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, including EnLink Midstream Operating, LP.

ENLINK MIDSTREAM, LLC

Our assets consist of equity interests in the Partnership and EnLink Oklahoma T.O. The Partnership is a publicly traded limited partnership that primarily focuses on providing midstream energy services, including gathering, processing, transmission, fractionation, storage, condensate stabilization, brine services and marketing to producers of natural gas, NGLs, crude oil and condensate. EnLink Oklahoma T.O. is a partnership held by us and the Partnership engaged in the gathering, transmission and processing of natural gas and NGLs. As of December 31, 2016, our interests in the Partnership consist of the following:

- 88,528,451 common units representing an aggregate 22.3% limited partner interest in the Partnership;
- 100.0% ownership interest in the General Partner, which owns a 0.4% general partner interest and all of the incentive distribution rights in the Partnership; and
- 16% limited partner interest in EnLink Oklahoma T.O.

Each of the Partnership and EnLink Oklahoma T.O is required by its partnership agreement to distribute all its cash on hand at the end of each quarter, less reserves established by it’s general partner in its sole discretion to provide for the proper conduct of the Partnership’s or EnLink Oklahoma T.O.’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 EnLink Oklahoma T.O. 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.

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.

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The following diagram depicts the organization and ownership of the Company and its subsidiaries as of December 31, 2016:

Definitions

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

/d = per day

Bbls = barrels

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

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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").

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

Our Operations

The Partnership primarily focuses on providing midstream energy services, including gathering, transmission, processing, fractionation, storage, condensate stabilization, brine services and marketing, to producers of natural gas, NGLs, crude oil and condensate. The Partnership's midstream energy asset network includes approximately 11,000 miles of pipelines, 20 natural gas processing plants, 7 fractionators, barge and rail terminals, product storage facilities, purchasing and marketing capabilities, brine disposal wells, a crude oil trucking fleet, and equity investments in certain private midstream companies. The Partnership's operations are based in the United States and its sales are derived primarily 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 end users or other pipelines. 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 920 MMcf/d, processing facilities with a total processing capacity of approximately 1.6 Bcf/d and gathering systems with total capacity of approximately 2.3 Bcf/d.

- Oklahoma. The Partnership's Oklahoma assets consist of processing facilities with a total processing capacity of approximately 795 MMcf/d and gathering systems with total capacity of approximately 810 MMcf/d.

- Louisiana. 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

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capacity of approximately 1.9 Bcf/d and gathering systems with total capacity of approximately 510 MMcf/d. The Partnership's Louisiana Liquids assets consists of 720 miles of liquids transport lines and four fractionation assets with total fractionation capacity of 175 MBbls/d.

· Crude and Condensate. The Partnership's Crude and Condensate assets consist of approximately 540 miles of crude oil and condensate pipelines. The assets also include 900,000 barrels of above ground storage and a trucking fleet of approximately 150 vehicles comprised of both semi and straight trucks with a current capacity of 85,350 Bbls/d. The current pipeline capacity is 116,100 Bbls/d. Additionally, 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"), an approximate 31% ownership interest in Howard Energy Partners ("HEP") and our approximate 30% ownership in Cedar Cove Midstream LLC ("Cedar Cove JV").

About Devon

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

Our Business Strategies

Our primary business objective is to provide cash flow stability in our business while growing prudently and profitably. We intend to accomplish this objective by 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 ("MVC") components of its contract portfolio to minimize its direct commodity price exposure.

· Maintain a strong financial position. The Partnership believes that maintaining a conservative and balanced capital structure, 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 throughout the cycles in its industry.

· Execute in our core growth 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 their 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 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 64.1% ownership interest in us and approximate 23.8% ownership interest in the Partnership as of December

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31, 2016. Approximately 50% of the Partnership's gross operating margin was attributable to commercial contracts with Devon in 2016.

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

· Stable cash flows. Approximately 97% of the Partnership's gross operating margin were generated from fee-based services with no direct commodity exposure during 2016. The Partnership currently has approximately seven 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 MVCs that will remain in effect for through January 1, 2019, as well as annual rate escalators. Additionally, the Partnership's EnLink Oklahoma T.O. assets are supported by Devon with acreage dedications and MVCs for gathering and processing on Devon's recently acquired Sooner Trend Anadarko Basin Canadian and Kingfisher Counties ("STACK") acreage. For additional information 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, storing, exporting and selling NGLs, and gathering, transporting, stabilizing, 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."

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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 commitment of 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 MVC was executed in June 2014 and the initial term expires in July 2019.

Recent Growth Developments

Acquisitions and Expansion

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

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

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

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

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

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

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

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

Organic Growth

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

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

Delaware Basin Joint Venture. On August 1, 2016, the Partnership formed the Delaware Basin JV with NGP to operate and expand their natural gas, natural gas liquids and crude oil midstream assets in the liquids-rich Delaware Basin. The Delaware Basin JV is owned 50.1% by the Partnership and 49.9% by NGP. The Partnership contributed approximately $221.0 million of existing assets, net of depreciation, to the Delaware Basin JV and committed an additional $285.0 million in capital to fund potential future development projects and potential acquisitions. NGP committed an aggregate of approximately $400.0 million of capital, including an initial contribution of $114.3 million, which the Delaware Basin JV distributed to the Partnership at the formation of the joint venture to reimburse the

Partnership for capital spent to the date of formation on existing assets and ongoing projects. In addition to the initial contributions, the Partnership and NGP contributed $30.2 million and $30.1 million, respectively, to the Delaware Basin JV for the year ended December 31, 2016. As part of this agreement, NGP granted the Partnership call rights beginning in 2021 to acquire increasing portions of NGP's interest in the joint venture at a price based upon a predetermined valuation methodology.

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

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

Ascension Joint Venture. The Partnership have formed a 50/50 joint venture named Ascension Pipeline Company, LLC (the "Ascension JV") with a subsidiary of Marathon Petroleum Corporation ("Marathon Petroleum") to build a new

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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. The Partnership commenced construction of the pipeline during 2016 and will operate the pipeline upon completion, which is currently estimated to be during the second quarter of 2017. This bolt-on project to the Partnership's Cajun-Sibon NGL system is supported by long-term, fee-based contracts with Marathon Petroleum.

Sale of Non-Core Assets

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

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

Acquisitions in 2014 and 2015

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

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

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

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

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

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

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

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Our Assets

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

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

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

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

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

(1) Volumes shown reflect only 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 fractionation 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 920 MMcf/d, processing facilities with a total processing capacity of approximately 1.6 Bcf/d and gathering systems with a capacity of approximately 2.3 Bcf/d.

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

· Processing and Fractionation Facilities. The Partnership's processing facilities in Texas include 10 gas processing plants and the Partnership's 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 Partnership's Bridgeport natural gas processing facility, located in Wise County, Texas, approximately 40 miles northwest of Fort Worth, Texas, is one of the largest processing plants in the U.S. with seven cryogenic turboexpander plants that have a total of 800 MMcf/d of processing capacity and 15 MBbls/d of NGL fractionation capacity. For the year ended December 31, 2016, throughput volumes at the Bridgeport processing facility averaged 662,000 MMBtu/d of natural gas. Devon is the Bridgeport facility's largest customer with approximately 656,700 MMBtu/d of natural gas processed for the year ended December 31, 2016. The Partnership currently has approximately seven 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 an MVC from Devon of 650 MMcf/d of natural gas delivered to the Bridgeport processing facility that will remain in effect through January 1, 2019 and also provides annual rate escalators.

· Silver Creek processing complex. 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, 2016, throughput volumes at the Silver Creek processing facility averaged 228,900 MMBtu/d of natural gas.

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· Permian Basin processing facilities. The Partnership's Permian Basin processing facilities consist of the following:

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

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

· Gathering Systems. The Partnership's gathering systems in Texas include approximately 4,400 miles of pipeline.

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

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

· Johnson County gathering system. This natural gas gathering system consists of approximately 290 miles of pipeline segments with approximately 44,000 horsepower of compression. Natural gas gathered on this system is delivered to intrastate pipelines without processing. For the year ended December 31, 2016, throughput volumes on the Johnson County gathering system averaged 143,200 MMBtu/d of natural gas, which were primarily attributable to Devon.

The Partnership currently has approximately seven years remaining on a fixed-fee gathering agreement pursuant to which the Partnership provides gathering services on the Johnson County gathering system. This contractual arrangement includes an MVC from Devon that will remain in effect through January 1, 2019, with 125 MMcf/d of natural gas to be delivered for gathering into the Johnson County gathering system and also provides annual rate escalators.

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

· Permian Basin assets. The Partnership's Permian Basin gathering systems include the following:

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

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

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

· Oklahoma processing system. The Partnership's processing facilities include the following:

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

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

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

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

- Oklahoma gathering system. The Partnership's Oklahoma gathering systems include the following:

- Central Oklahoma gathering system. The Partnership's central Oklahoma gathering system consists of the 350-mile Chisholm gathering system with approximately 80,000 horsepower of compression, the 250-mile Battle Ridge gathering system with approximately 38,000 horsepower of compression and the 440-mile Cana gathering system with approximately 88,000 horsepower of compression (collectively, the "central Oklahoma gathering system"). The central Oklahoma gathering system serves the STACK and CNOW plays. For the year ended December 31, 2016, throughput averaged

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585,200 MMbtu/d. In addition, contractual arrangements related to the central Oklahoma gathering system that contain an MVC include the following:

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

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

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

Louisiana Assets. 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 1.9 Bcf/d and gathering systems with total capacity of approximately 510 MMcf/d.

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

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

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

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

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

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

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· 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 Partnership's share of the plant's capacity is approximately 193 MMcf/d. The plant is not expected to operate in the future unless fractionation spreads are favorable and volumes are sufficient to run the plant.

· Eunice Processing Plant. The Eunice processing plant is located in south central Louisiana and has a capacity of 475 MMcf/d of natural gas. In August 2013, 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 11.9 Bcf. This facility was placed in service in May 2016 and is designed for injecting pipeline quality gas into storage or withdrawing stored gas for delivery by pipeline. The storage facility includes three compressors with a total of 9,637 horsepower.

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

· Louisiana Liquids Pipeline System. The Partnership's Louisiana liquids pipeline system includes approximately 720 miles of liquids transport lines, processing and fractionation assets and underground storage.

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

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

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

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

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

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

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

Crude and Condensate. The Partnership's Crude and Condensate assets consist of approximately 540 miles of crude oil and condensate pipelines. The assets also include 900,000 barrels of above ground storage and a trucking fleet of approximately 150 vehicles comprised of both semi and straight trucks with a current capacity of 85,350 Bbls/d. The current pipeline capacity is 116,100 Bbls/d. Additionally, 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 trailers for hauling NGL volumes with a current capacity of 25,650 Bbls/d. Total crude oil and condensate handled averaged approximately 19,900 Bbls/d for the year ended December 31, 2016. The Partnership has eight existing brine disposal wells with an injection capacity of approximately 4,000 Bbls/d and an average disposal rate of 3,600 Bbls/d for the year ended December 31, 2016. Additionally, our ORV operations include eight condensate stabilization and natural gas compression stations with combined capacities of over 36,000 Bbls/d of condensate stabilization and 780 MMcf/d of natural gas compression. These stations are in service and are supported by long-term, fee-based contracts with multiple producers.

· Permian Crude and Condensate. 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 85,800 Bbls/d. Their integrated logistics services are supported by 54 tractor trailers, 14 pipeline injection stations and 85 miles of crude oil gathering pipeline. Total crude oil and condensate handled averaged approximately 54,500 Bbls/d for the year ended December 31, 2016.

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

· Victoria Express Pipeline. The VEX pipeline is a 60-mile, multi-grade crude oil pipeline with a current capacity of approximately 90,000 Bbls/d. Other VEX assets include the Cuero Terminal and Port of Victoria Terminal and Barge Docks. The Cuero truck unloading terminal at the origin of the VEX system contains 8 unloading bays and 200,000 bbls of above-ground storage capacity for receipt from and delivery to the VEX pipeline. The VEX pipeline terminates at the Port of Victoria Terminal that also has an 8-bay truck unloading dock and 200,000 bbls of above-ground storage capacity. The Port of Victoria Terminal

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delivers to two barge loading docks at the Port of Victoria. Total crude oil and condensate handled averaged approximately 14,500 Bbls/d for the year ended December 31, 2016. The Partnership has an agreement with Devon, which includes an MVC of 30,000 Bbls/d, that will remain in effect until July 2019.

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, an approximate 31% ownership interest in HEP, and a 30% ownership interest in the Cedar Cove Joint Venture.

· 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 22.5% by Phillips 66 and 38.75% by Targa Resources Partners. GCF owns an NGL fractionator located on the Gulf Coast at Mont Belvieu, Texas. Phillips 66 is the operator of the fractionator. GCF receives raw mix NGLs from customers, fractionates the raw mix and redelivers the finished products to the customers for a fee. The facility has a capacity of approximately 145 MBbls/d. The plant fractionated approximately 38,000 Bbls/d of liquids for the year ended December 31, 2016.

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

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

Industry Overview

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

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

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

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

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

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

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

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

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

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

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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 New York Mercantile Exchange ("NYMEX") related to its natural gas purchases. Through these transactions, the Partnership seeks to maintain a position that is balanced between (1) purchases and (2) sales or future delivery obligations. 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. The Partnership's 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. As a result of certain of the Partnership's contractual relationships with Devon, the Partnership will not compete for the portion of Devon's existing operations subject to existing acreage dedication for the terms of such contracts. For areas where acreage is not dedicated to us, we will compete with similar enterprises in providing additional gathering and processing services in its respective areas of operation, which may offer more services or have strong financial resources and access to larger natural gas, NGLs, crude oil and condensate supplies than we do. Our competition varies in different geographic areas.

In marketing natural gas, NGLs, crude oil and condensate 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 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 an MVC 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

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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 lower commodity prices, a reduction in borrowing bases under reserve-based credit facilities and the lack of availability of debt or equity financing may result in a significant reduction in the Partnership’s customers’ liquidity and ability to make payment or perform on their 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. 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 years ended December 31, 2016, 2015 and 2014, Devon represented 18.5%, 16.6% and 30.6%, respectively, of the Partnership’s consolidated revenues and Dow Hydrocarbons & Resources LLC (“Dow Hydrocarbons”) represented 10.8%, 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 us under commercial agreements, which constitutes a substantial portion of the Partnership’s natural gas supply. The loss of Devon or Dow Hydrocarbons as a customer could have a material impact on the Partnership’s results of operations if it were not able to gather, transport or process Devon’s gas or sell Dow Hydrocarbons’ products to another customer with similar margins because the gross operating margins received from transactions with Devon and Dow Hydrocarbons are material to the Partnership’s total gross operating margin.

Regulation

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

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

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

Interstate natural gas pipelines regulated by FERC are required to comply with numerous regulations related to standards of conduct, market transparency, and market manipulation. FERC's standards of conduct regulate the manner in which interstate natural gas pipelines may interact with their marketing affiliates. FERC's market oversight and transparency regulations require regulated entities to submit annual reports of threshold purchases or sales of natural gas and publicly post certain information on scheduled volumes. FERC's market manipulation regulations, promulgated pursuant to the Energy Policy Act of 2005 (the "EPAct 2005"), make it unlawful for any entity, directly or indirectly in connection with the purchase or sale of natural gas subject to the jurisdiction of FERC, or the purchase or sale of transportation services subject to the jurisdiction of FERC, to (1) use or employ any device, scheme or artifice to defraud; (2) make any untrue statement of material fact or omit to make any statement necessary to make the statements made not misleading; or (3) engage in any act or practice that operates as a fraud or deceit upon any person. The EPAct 2005 also amends the NGA and the Natural Gas Policy Act of 1978 ("NGPA") to give FERC authority to impose civil penalties for violations of these statutes up to $1.0 million per day per violation for violations occurring after August 8, 2005. The maximum penalty authority established by the statute has been and will continue to be adjusted periodically for inflation. Should the Partnership fail to comply with all applicable FERC-administered statutes, rules, regulations and orders, the Partnership could be subject to substantial penalties and fines.

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

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

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

Rates of interstate liquids pipelines are currently regulated by FERC primarily through an annual indexing methodology, under which pipelines increase or decrease their rates in accordance with an index adjustment specified by FERC. This adjustment is subject to review every five years. For the five-year period beginning on July 1, 2016, FERC established an annual index adjustment equal to the change in the producer price index for finished goods plus 1.23%. On October 20, 2016, however, FERC issued an Advance Notice of Proposed Rulemaking indicating that

FERC is considering a new policy that would deny proposed index increases for pipelines under certain circumstances where revenues exceed cost-of-service by a certain percentage or where the proposed index increases exceed certain annual cost changes reported to FERC. Under current FERC regulations, liquids pipelines can request a rate increase that exceeds the rate obtained through application of the indexing methodology by using a cost-of-service approach, but only after the pipeline establishes that a substantial divergence exists between the actual costs experienced by the pipeline and the rates resulting from application of the indexing methodology. The rates charged by the Partnership's interstate liquids pipelines may also be affected by the ongoing uncertainty regarding FERC's current income tax allowance policy discussed above.

The ICA permits interested persons to challenge proposed new or changed rates and authorizes FERC to suspend the effectiveness of such rates for up to seven months and investigate such rates. If, upon completion of an investigation, FERC finds that the new or changed rate is unlawful, it is authorized to require the pipeline to refund revenues collected in excess of the just and reasonable rate during the term of the investigation. FERC may also investigate, upon complaint or on its own motion, rates that are already in effect and may order a carrier to change its rates prospectively. Under certain circumstances, FERC could limit the Partnership's ability to set rates based on its costs or could order the Partnership to reduce its rates and pay reparations to complaining shippers for up to two years prior to the date of the complaint. FERC also has the authority to change 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 the Partnership provides and determinations by FERC and the courts. Such changes may subject additional services the Partnership provides to regulation by FERC.

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

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

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

In addition, 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.

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

Sales of Natural Gas and NGLs. The prices at which 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, cost and regulation of pipeline transportation.

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

The Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011 increased penalties for safety violations, established additional safety requirements for newly constructed pipelines and required studies of certain safety issues that could result in the adoption of new regulatory requirements for existing pipelines. In April 2016, PHMSA published a notice of proposed rulemaking, or NPRM, addressing natural gas transmission and gathering lines. The proposed rule would, among other things, change existing integrity management requirements, expand assessment and repair requirements to pipelines in "moderate-consequence areas," including areas of medium population density and increase requirements for monitoring and inspection of pipeline segments located outside of HCAs. Further, this NPRM would require that records or other data relied on to determine operating pressures must be traceable, verifiable and complete. Locating such records and, in the absence of any such records, verifying maximum pressures through physical testing or modifying or replacing facilities, could significantly increase the Partnership's costs. Additionally, failure to locate such records or verify maximum pressures could result in the reduction of allowable operating pressures, which would reduce available capacity on the Partnership's pipelines.

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

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

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

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

On November 2, 2015, PHMSA issued a Notice of Probable Violation and Proposed Compliance Order (the "NOPV") asserting that 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 us 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 took place on July 27, 2016, and the Partnership is awaiting a decision from PHMSA regarding the arguments presented at the hearing. We cannot predict the outcome of the Partnership's challenge. In the event the pipeline in question is ultimately treated as a transmission line rather than a

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gathering line, the Partnership estimates that it would incur costs of approximately $2.1 million over a two-year period to develop and implement a Part 195-compliant integrity management program, including hydrostatic testing and a leak detection and repair program.

Environmental Matters

General. 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 hydrocarbons. 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 discharge of hazardous substances or solid wastes into the environment or otherwise relating to protection of the environment. Compliance with existing and anticipated environmental laws and regulations increases the Partnership's overall costs of doing business, including costs of planning, constructing, and operating plants, pipelines, and other facilities, as well as capital expenditures necessary to maintain or upgrade equipment and facilities. Similar costs are likely upon changes in laws or regulations and upon any future acquisition of operating assets.

Any failure to comply with applicable environmental laws and regulations, including those relating to equipment failures, and obtaining required governmental approvals, may result in the assessment of administrative, civil or criminal penalties, imposition of investigatory or remedial activities and, in certain, less common circumstances, issuance of temporary or permanent injunctions or construction or operation bans or delays. As part of the regular evaluation of 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. The Partnership may be unable to pass on current or future environmental costs to its customers. A discharge or release of hydrocarbons, hazardous substances, or solid wastes into the environment could, to the extent losses related to the event are not insured, 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, sediments, groundwater and surface water and/or include measures to prevent and control pollution may pose the highest potential cost to our industrial sector. These laws and regulations generally regulate the generation, storage, treatment, transportation and disposal of solid wastes and hazardous substances and may require investigatory and corrective actions at facilities where such waste or substance may have been released or disposed. For instance, the Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA"), also known as the federal "Superfund" law, and comparable state laws impose liability without regard to fault or the legality of the original conduct on certain classes of persons that contributed to a release of a "hazardous substance" into the environment. Potentially responsible persons include the owner or operator of the site where a release occurred and companies that disposed or arranged for the disposal of the hazardous substances found at an off-site location, such as a landfill. Under CERCLA, these persons may be subject to joint and several liability for the costs of cleaning up and restoring sites where hazardous substances have been released into the environment and for damages to natural resources. CERCLA also authorizes the U.S. Environmental Protection Agency ("EPA") and, in some cases, third parties to take actions in response to threats to public health or the environment and to seek recovery of costs they incur from the potentially responsible classes of persons. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or solid wastes released into the environment. Although petroleum, natural gas and NGLs are excluded from CERCLA's definition of a "hazardous substance," in the course of ordinary operations, the Partnership may generate wastes that may fall within the

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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, state, or local 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 are currently exempted from the definition of hazardous waste may in the future lose this exemption and be designated as “hazardous wastes,” resulting in the wastes being subject to more rigorous and costly management and disposal requirements. Additionally, the Toxic Substances Control Act (“TSCA”) and analogous state laws impose requirements on the use, storage and disposal of various chemicals and chemical substances. Changes in applicable laws or regulations may result in an increase in 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 solid wastes may have been released on or under various properties owned, leased or operated by the Partnership during the operating history of those properties. In addition, a number of these properties may have been operated by third parties over whose operations and hydrocarbon and waste management practices the Partnership had no control. These properties and wastes disposed thereon may be subject to the Safe Drinking Water Act, CERCLA, RCRA, TSCA and analogous state laws. Under these laws, the Partnership could be required, alone or in participation with others, to remove or remediate previously disposed wastes or property contamination, if present, including groundwater contamination, or to take action to prevent future contamination.

Air Emissions. The Partnership’s current and future operations are subject to the federal Clean Air Act and regulations promulgated thereunder and under comparable state laws and regulations. These laws and regulations regulate emissions of air pollutants from various industrial sources, including the Partnership’s facilities, and impose various control, monitoring and reporting requirements. Pursuant to these laws and regulations, the Partnership may be required to obtain environmental agency pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions or result in an increase in existing air emissions, obtain and comply with the terms of air permits, which include various emission and operational limitations, or use specific emission control technologies to limit emissions. The Partnership likely will be required to incur certain capital expenditures in the future for air pollution control equipment in connection with maintaining or obtaining governmental approvals addressing air emission-related issues. Failure to comply with applicable air statutes or regulations may lead to the assessment of administrative, civil or criminal penalties and may result in the limitation or cessation of construction or operation of certain air emission sources or require us to incur additional capital expenditures. Although we can give no assurances, we believe such requirements will not have a material adverse effect on the Partnership’s financial condition, results of operations, or cash flows, 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 the Partnership's Bridgeport facility, in its January 2012 revision to the Dallas-Ft. Worth ozone nonattainment area for the 2008 revised ozone national ambient air quality standard ("NAAQS"). As a result of this designation, new major sources in Wise County, meaning sources that emit greater than 100 tons/year of nitrogen oxides ("NOx") and volatile organic compounds ("VOCs"), as well as major modifications of existing facilities in the county resulting in net emissions increases of greater than 40 tons/year of NOx or VOCs, are subject to more stringent new source review ("NSR") pre-construction permitting requirements than they would be in an area that is in attainment with the 2008 ozone NAAQS. NSR pre-construction permits can take twelve to eighteen months to obtain and require the permit applicant to offset the proposed emission increases with reductions elsewhere at a 1.15 to 1 ratio. On October 26, 2016, the EPA finalized its 2015 revised ozone NAAQS that, if implemented, will further restrict ozone within the Dallas-Ft. Worth nonattainment area. The 2015 ozone NAAQS are being challenged in the U.S. Court of Appeals for the D.C. Circuit. The appeal remains pending.

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

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

Climate Change. In December 2009, the EPA determined that emissions of certain gases, commonly referred to as “greenhouse gases,” present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to the warming of the earth’s atmosphere and other climatic changes. Based on these findings, the EPA adopted regulations under existing provisions of the federal Clean Air Act, that require Prevention of Significant Deterioration (“PSD”) pre-construction permits, and Title V operating permits for greenhouse gas emissions from certain large stationary sources. Under these regulations, facilities required to obtain PSD permits must meet “best available control technology” standards for their greenhouse gas emissions established by the states or, in some cases, by the EPA on a case by case basis. The EPA has also adopted rules requiring the monitoring and reporting of greenhouse gas emissions from specified sources in the United States, including, among others, certain onshore oil and natural gas processing and fractionating facilities.

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. In addition, in 2015, the United States participated in the United

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Nations Conference on Climate Change, which led to the creation of the Paris Agreement. The Paris Agreement entered into force November 4, 2016, and requires countries to review and "represent a progression" in their intended nationally determined contributions, which set GHG emission reduction goals every five years beginning in 2020. The status of the United States' commitment to Paris Agreement under the Trump Administration remains to be determined. Due to the uncertainties surrounding the regulation of and other risks associated with greenhouse gas emissions, we cannot predict the financial impact of related developments on 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 condition, results of operations and cash flows.

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

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 federal SDWA, such as the Ohio Department of Natural Resources rules that took effect October 1, 2012. These rules set new, more stringent standards for the permitting and operating of brine disposal wells, including extensive review of geologic data and use of state-of-the-art technology. The Ohio Department of Natural Resources also imposes requirements on the transportation and disposal of brine. Compliance with current and future laws and regulations regarding our brine disposal wells may impose substantial costs and restrictions on the Partnership's 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

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the tens of thousands of injection wells have been suspected to be, or have been, the likely cause of induced seismicity. However, some state regulatory agencies have modified their regulations to account for induced seismicity. For example, TRRC rules allow the TRRC to modify, suspend, or terminate a permit based on a determination that the permitted activity is likely to be contributing to seismic activity. In the state of Ohio, the Ohio Department of Natural Resources ("ODNR") requires a seismic study prior to the authorization of any new disposal well. In addition, the ODNR has instituted a continuous monitoring network of seismographs and is able to curtail injected volumes regionally based upon seismic activity detected. The Oklahoma Corporation Commission has also taken steps to focus on induced seismicity, including increasing the frequency of required recordkeeping for wells that dispose into certain formations and considering seismic information in permitting decisions. For instance, on August 3, 2015, the OCC adopted a plan calling for mandatory reductions in oil and gas wastewater disposal well volumes, the implementation of which has involved reductions of injection or shut-ins of disposal wells. Regulatory agencies are continuing to study possible linkage between injection activity and induced seismicity. To the extent these studies result in additional regulation of injection wells, such regulations could impose additional regulations, costs and restrictions on 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 of the Partnership's customers and suppliers. There are certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices, and a committee of the United States House of Representatives has conducted an investigation of hydraulic fracturing practices. On December 13, 2016, the EPA released a study of the potential adverse effects that hydraulic fracturing may have on water quality and public health, concluding that there is scientific evidence that hydraulic fracturing activities potentially can impact drinking water resources in the United States under some circumstances. This study or similar studies could spur initiatives to further regulate hydraulic fracturing. In June 2016, the EPA finalized rules prohibiting discharges of wastewater from hydraulic fracturing operations to publicly owned wastewater treatment plants. The EPA has also issued an advance notice of proposed rulemaking under the Toxic Substances Control Act to gather information regarding the potential regulation of chemical substances and mixtures used in oil and gas exploration and production. Also, effective June 24, 2015, BLM adopted rules regarding well stimulation, chemical disclosures, water management, and other requirements for hydraulic fracturing on federal and Indian lands; however, a federal district court invalidated these BLM rules in June 2016 and an appeal is pending. Additional regulatory burdens in the future, whether federal, state or local, could increase the cost of or restrict the ability of 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 our gathering systems which would materially adversely affect the Partnership's revenues and results of operations or cash flows.

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

The Endangered Species Act can also make it more difficult to secure a federal permit for a new pipeline.

Office Facilities

The Partnership occupies approximately 109,400 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.

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Employees

As of December 31, 2016, the Partnership (through its subsidiaries) employed approximately 1,472 full-time employees. Approximately 336 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, results of operations, cash flows (including our ability to make distributions to our noteholders) could be affected materially and adversely. In that case, we may be unable to make distributions to our unitholders and the trading price of our common units could decline. Because EnLink Oklahoma T.O. 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 EnLink Oklahoma T.O. when applicable, including general references to the Partnership's business in the following risk factors. 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 64.1% of our outstanding common units as of February 8, 2017 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 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;

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

- 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 has 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 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
- 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

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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 66 2/3% of all outstanding common units voting together as a single class is required to remove the managing member. As of February 8, 2017, the Managing Member and its affiliates owned approximately 64.1% of the outstanding ENLC 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

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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 8, 2017, 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 units 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 8, 2017, Devon owned an aggregate of approximately 64.1% 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

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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 8, 2017, only approximately 35.9% 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.

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

Currently, our only cash-generating assets are our partnership interests in the Partnership and our 16% limited partner interest in EnLink Oklahoma T.O. Although EnLink Oklahoma T.O. generates positive cash flows from operating activities, our capital contributions exceeded distributions received during 2016, and estimated capital contributions during 2017 will exceed its cash flows from operating activities. We have a credit facility in place to fund our share of capital expenditures to the extent not funded by EnLink Oklahoma T.O.'s operating cash flows. See "Item 8. Financial Statements and Supplementary Data—Note 6" for further discussion. If our borrowing capacity under this facility is not sufficient to fund our share of EnLink Oklahoma T.O.'s capital expenditures, we may have to use our cash flow from Partnership distributions to fund such costs. 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
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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.