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

FORM 8-K

CURRENT REPORT
Pursuant to Section 13 or 15(d)
of the Securities Exchange Act of 1934

Date of Report (date of earliest event reported): **March 7, 2014**

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

DELAWARE	**001-36340**	**16-1616605**
(State or Other Jurisdiction of Incorporation or Organization)	(Commission File Number)	(I.R.S. Employer Identification No.)

2501 CEDAR SPRINGS RD. **DALLAS, TEXAS**	**75201**
(Address of Principal Executive Offices)	(Zip Code)

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

Crosstex Energy, L.P.
(Former name or former address, if changed since last report)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions (*see* General Instruction A.2. below):

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)
☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)
☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))
☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Item 2.01. Completion of Acquisition or Disposition of Assets.

Contribution Agreement Closing

On March 7, 2014, EnLink Midstream Partners, LP (formerly known as Crosstex Energy, L.P.)(the "Partnership") consummated the transactions contemplated by the Contribution Agreement, dated as of October 21, 2013 (the "Contribution Agreement"), among the Partnership, EnLink Midstream Operating, LP (formerly known as Crosstex Energy Services, L.P.), a wholly-owned subsidiary of the Partnership ("EnLink Midstream Operating"), Devon Energy Corporation ("Devon"), Devon Gas Corporation, Devon Gas Services, L.P. ("Gas Services") and Southwestern Gas Pipeline, Inc. ("Southwestern Gas" and, together with Gas Services, the "Contributors") pursuant to which the Contributors contributed (the "Contribution") to EnLink Midstream Operating a 50% limited partner interest in EnLink Midstream Holdings, LP ("Midstream Holdings") and all of the outstanding equity interests in EnLink Midstream Holdings GP, LLC, the general partner of Midstream Holdings ("Midstream Holdings GP" and, together with Midstream Holdings and their subsidiaries, the "Midstream Group Entities"), in exchange for the issuance by the Partnership of 120,542,441 units representing a new class of limited partnership interests in the Partnership (the "Class B Units"). The Midstream Group Entities own midstream assets previously held by Devon in the Barnett Shale in North Texas, the Cana and Arkoma Woodford Shales in Oklahoma and a contractual right to the benefits and burdens associated with Devon's interest in Gulf Coast Fractionators in Mt. Belvieu, Texas.

The Class B Units represent approximately 52% of the outstanding limited partner interests in the Partnership, with approximately 40% of the outstanding limited partner interests held by the Partnership's public unitholders and approximately 7% of the outstanding limited partner interests, the approximate 1% general partner interest and the incentive distribution rights held indirectly by EnLink Midstream, LLC ("EnLink Midstream"). The Class B Units are substantially similar in all respects to the Partnership's common units representing limited partnership interests in the Partnership ("Common Units"), except that they will only be entitled to a pro rata distribution for the fiscal quarter ended March 31, 2014. The Class B Units will automatically convert into Common Units on a one-for-one basis on the first business day following the record date with respect to the distribution for the quarter ended March 31, 2014. The private placement of the Class B Units pursuant to the Contribution Agreement was made in reliance upon an exemption from the registration requirements of the Securities Act of 1933, as amended (the "Securities Act"), pursuant to Section 4(2) thereof.

A copy of the Contribution Agreement was filed as Exhibit 2.1 to the Current Report on Form 8-K filed by the Partnership with the Securities and Exchange Commission on October 22, 2013 and is incorporated herein by reference.

Merger Agreement Closing

Also on March 7, 2014, Crosstex Energy, Inc. (the "Corporation") and Devon consummated the transactions contemplated by the Merger Agreement, dated as of October 21, 2013 (the "Merger Agreement"), among the Corporation, Devon, EnLink Midstream, Acacia

Natural Gas Corp I, Inc., formerly a wholly-owned subsidiary of Devon ("New Acacia"), and certain other wholly-owned subsidiaries of Devon pursuant to which the Corporation and New Acacia each became wholly-owned subsidiaries of EnLink Midstream (collectively, the "Mergers" and together with the Contribution, the "business combination”). As a result of the merger with New Acacia, EnLink Midstream indirectly owns the remaining 50% limited partner interest in Midstream Holdings.

Upon the closing of the Mergers, EnLink Midstream issued 115,495,669 Class B common units of EnLink Midstream (the “EnLink Midstream Class B Units”) to a wholly-owned subsidiary of Devon, which units represent approximately 70% of the outstanding limited liability company interests in EnLink Midstream, with the remaining 30% held by the former stockholders of the Corporation. Upon the closing of the Mergers, each issued and outstanding share of the Corporation’s common stock was converted into the right to receive (i) one common unit representing a limited liability company interest in EnLink Midstream (each, an “EnLink Midstream Common Unit”) and (ii) an amount in cash equal to approximately $2.06, which is an amount equal to the quotient of (x) $100,000,000 divided by (y) the number of shares of Crosstex common stock issued and outstanding immediately prior to the effective time of the Mergers.

The EnLink Midstream Class B Common Units are substantially similar in all respects to the EnLink Midstream Common Units, except that they will only be entitled to a pro rata distribution for the fiscal quarter ended March 31, 2014. The EnLink Midstream Class B Units will automatically convert into EnLink Midstream Common Units on a one-for-one basis on the first business day following the record date for distribution payments with respect to the distribution for the quarter ended March 31, 2014. The private placement of the EnLink Midstream Class B Units pursuant to the Merger Agreement was made in reliance upon an exemption from the registration requirements of the Securities Act pursuant to Section 4(2) thereof.

A copy of the Merger Agreement was filed as Exhibit 2.1 to the Current Report on Form 8-K filed by the Corporation with the Securities and Exchange Commission on October 22, 2013 and is incorporated herein by reference.

Item 3.02. Unregistered Sales of Equity Securities.

The information set forth under Item 2.01 of this Current Report under the heading “Contribution Agreement Closing” regarding the issuance and sale of Class B Units to the Contributors is incorporated herein by reference.

Item 8.01. Other Events.

In connection with the closing of the business combination, the Partnership is providing business information and information about the risks relating to the Partnership’s business, certain historical financial statements of EnLink Midstream Holdings, LP Predecessor, selected financial data and management’s discussion and analysis of financial condition and results of operations with respect to the historical financial statements and, finally, pro forma financial

statements of the Partnership giving effect to the Contribution Closing, which are filed as Exhibits 99.1, 99.2, 99.3, 99.4 and 99.5 to this Current Report and are incorporated herein by reference.

Item 9.01. Financial Statements and Exhibits.

(a) *Financial Statements of Business Acquired*

The audited consolidated financial statements of EnLink Midstream Holdings, LP Predecessor for the years ended December 31, 2011, 2012 and 2013, together with the report of KPMG LLP with respect thereto, are included as Exhibit 99.4 to this Current Report and are incorporated herein by reference. Under the acquisition method of accounting, Midstream Holdings is considered the historical predecessor of the Partnership’s business because Devon obtained control of the Partnership through its control of EnLink Midstream and EnLink Midstream’s indirect acquisition of EnLink Midstream GP, LLC (formerly known as Crosstex Energy GP, LLC) concurrently with the consummation of the business combination.

(b) *Pro Forma Financial Information*

The unaudited pro forma financial statements of the Partnership required by this item are included as Exhibit 99.5 to this Current Report and are incorporated herein by reference.

(d) *Exhibits.*

EXHIBIT NUMBER		DESCRIPTION
23.1	—	Consent of KPMG LLP.
99.1	—	Business Information Regarding EnLink Midstream Partners, LP.
99.2	—	Risk Factors Related to EnLink Midstream Partners, LP.
99.3	—	Selected Financial Data of EnLink Midstream Holdings, LP Predecessor and Management’s Discussion and Analysis of Financial Condition and Results of Operations of the Partnership.
99.4	—	EnLink Midstream Holdings, LP Predecessor Audited Financial Statements for the Years Ended December 31, 2011, 2012 and 2013.
99.5	—	Unaudited Pro Forma Financial Statements of EnLink Midstream Partners, LP.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the Partnership has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

ENLINK MIDSTREAM PARTNERS, LP

By: EnLink Midstream GP, LLC, its General Partner

Date: March 10, 2014

By: /s/ Michael J. Garberding
Michael J. Garberding
Executive Vice President and
Chief Financial Officer

INDEX TO EXHIBITS

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99.4	—	EnLink Midstream Holdings, LP Predecessor Audited Financial Statements for the Years Ended December 31, 2011, 2012 and 2013.
99.5	—	Unaudited Pro Forma Financial Statements of EnLink Midstream Partners, LP.

Exhibit 23.1

Consent of Independent Registered Public Accounting Firm

The Board of Directors
Devon Energy Corporation:

We consent to the incorporation by reference in the registration statement (No. 333-188047, 333-188041) on Form S-3 and (No. 333-107025, 333-127645, 333-159140, 333-188678) on Form S-8 of EnLink Midstream Partners, LP (formerly known as Crosstex Energy, L.P.) of our report dated March 7, 2014, with respect to the combined balance sheets of EnLink Midstream Holdings, LP Predecessor as of December 31, 2013 and 2012, and the related combined statements of operations, equity, and cash flows for each of the years in the three-year period ended December 31, 2013, which report appears in the Form 8-K of EnLink Midstream Partners, LP dated March 7, 2014.

/s/ KPMG LLP

Oklahoma City, Oklahoma
March 7, 2014

Exhibit 99.1

BUSINESS INFORMATION REGARDING
ENLINK MIDSTREAM PARTNERS, LP

Overview

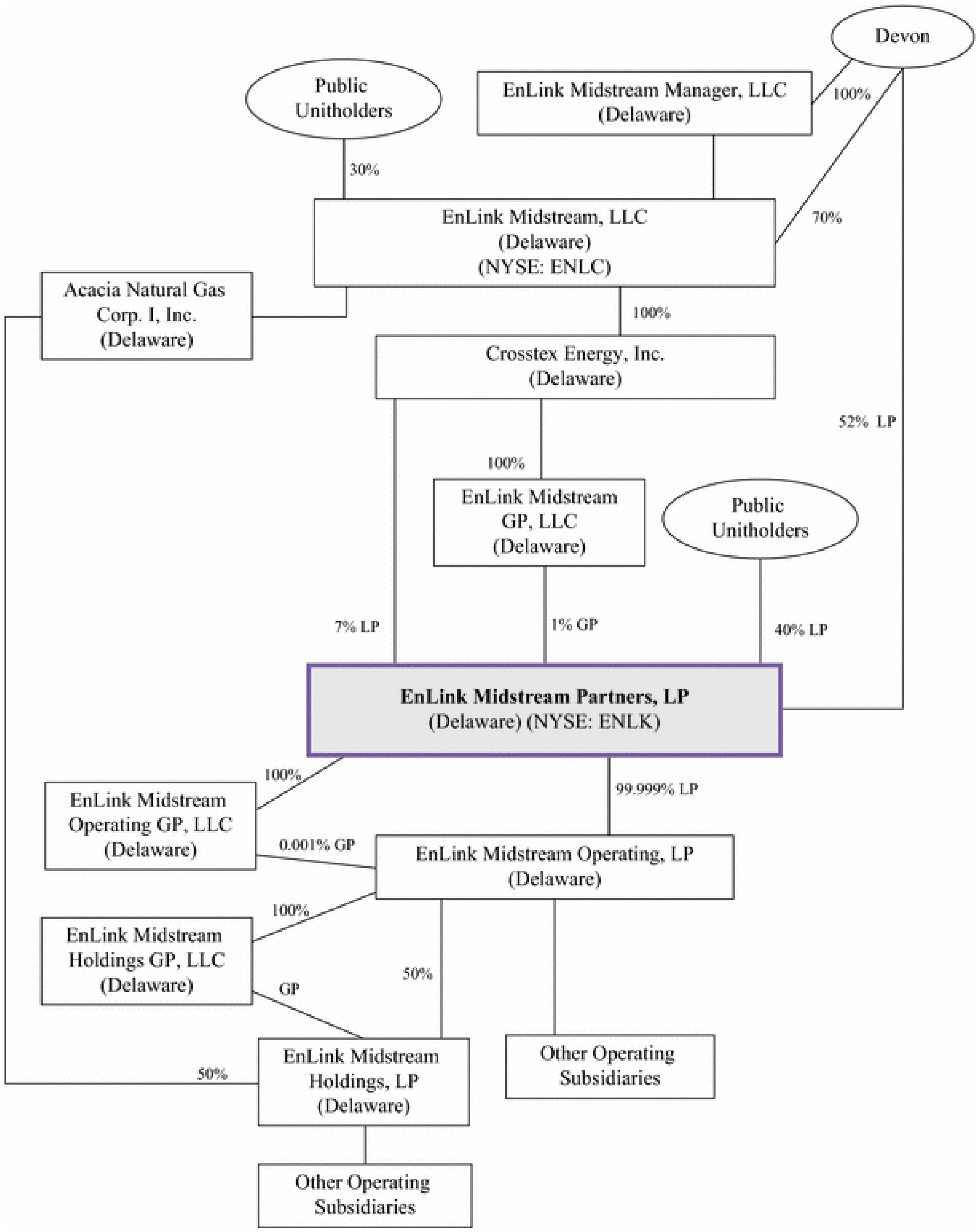
EnLink Midstream Partners, LP (formerly known as Crosstex Energy, L.P.) is a publicly traded Delaware limited partnership formed in 2002. Our common units are traded on the New York Stock Exchange under the symbol “ENLK.” Our business activities are conducted through our subsidiary, EnLink Midstream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

EnLink Midstream GP, LLC (formerly known as Crosstex Energy GP, LLC), a Delaware limited liability company, is our general partner (the “General Partner”). Our General Partner manages our operations and activities. Our General Partner is an indirect wholly-owned subsidiary of EnLink Midstream, LLC (“ENLC”). ENLC’s units are traded on the New York Stock Exchange under the symbol “ENLC.” ENLC’s manager is an indirect wholly-owned subsidiary of Devon Energy Corporation (“Devon”).

Effective as of March 7, 2014, the Operating Partnership acquired (the “Acquisition”) 50% of the outstanding equity interests in EnLink Midstream Holdings, LP (“Midstream Holdings”) and all of the outstanding equity interests in EnLink Midstream Holdings GP, LLC, the general partner of Midstream Holdings, in exchange for the issuance by the Partnership of 120,542,441 units representing a new class of limited partnership interests in the Partnership. At the same time, Crosstex Energy, Inc. (to be renamed EnLink Midstream, Inc.) (“CEI”), the entity that directly owns our General Partner, became a wholly-owned subsidiary of ENLC (together with the Acquisition, the “business combination”). Another wholly-owned subsidiary of ENLC owns the remaining 50% of the outstanding equity interests in Midstream Holdings. In this report, the term “Midstream Holdings” is sometimes used to refer to EnLink Midstream Holdings, LP itself or to EnLink Midstream Holdings, LP together with EnLink Midstream Holdings GP, LLC and their subsidiaries.

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

The following diagram depicts the organization and ownership of the Partnership following the completion of the business combination and the respective name changes:



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
CO_2= Carbon dioxide
Mcf = thousand cubic feet

MMBtu = million British thermal units
MMcf = million cubic feet
NGL = natural gas liquid and natural gas liquids

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

Our Operations

We are a Delaware limited partnership formed on July 12, 2002. We primarily focus on providing midstream energy services, including gathering, transmission, processing, fractionation and marketing, to producers of natural gas, NGLs, crude oil and condensate. We also provide crude oil, condensate and brine services to producers. Our midstream energy asset network includes approximately 7,300 miles of pipelines, 12 natural gas processing plants, six fractionators, 3.1 million barrels of NGL cavern storage, rail terminals, barge terminals, truck terminals and a fleet of approximately 100 trucks.

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

Our assets are comprised of systems and other assets in which our interest is held through our wholly-owned subsidiaries as well as systems and other assets owned by Midstream Holdings, in which we hold a 50% interest, and are located in four primary regions:

- *Texas*. Our Texas assets consist of transmission pipelines with a capacity of approximately 1.3 Bcf/d, processing facilities with a total processing capacity of approximately 1.1 Bcf/d and gathering systems with total capacity of approximately 2.5 Bcf/d. Some of the primary assets comprising our Texas assets are as follows:
  - *North Texas Pipeline and Acacia transmission system*. Our North Texas Pipeline ("NTPL"), is a 140-mile pipeline that connects production from the Barnett Shale to markets in north Texas with approximately 375 MMcf/d of capacity. Average throughput on the NTPL was approximately 342,000 MMBtu/d for the year ended December 31, 2013. The Acacia transmission system, which is owned by Midstream Holdings, consists of approximately 120 miles of pipeline and associated storage with approximately 920 MMcf/d of capacity. Average throughput on the Acacia transmission system was approximately 741,800 MMBtu/d for the year ended December 31, 2013.
  - *Bridgeport processing facility*. The Bridgeport processing facility, which is owned by Midstream Holdings, is one of the largest processing plants in the U.S. with 790 MMcf/d of processing capacity and 15

MBbls/d of NGL fractionation capacity. Average throughput on the Bridgeport processing facility was 810,600 MMBtu/d for the year ended December 31, 2013.

  - *Silver Creek processing complex*. Our Silver Creek processing complex includes three processing plants with an aggregate of 285 MMcf/d of processing capacity. Average throughput on the Silver Creek processing complex was 316,000 MMBtu/d for the year ended December 31, 2013.
  - *Permian Basin Assets*. Our Permian Basin assets consist of our Deadwood natural gas processing plant, which has a total processing capacity of 58 MMcf/d and in which we have a 50% undivided working interest, and our Mesquite Terminal fractionator, which has 15,000 Bbls/d of NGL fractionation capacity. Average throughput on the Deadwood natural gas processing plant was 66,000 MMBtu/d for the year ended December 31, 2013.
  - *Gulf Coast Fractionators*. Midstream Holdings is entitled to receive the economic benefits and burdens of the 38.75% interest in Gulf Coast Fractionators held by Devon. Gulf Coast Fractionators owns an NGL fractionator located on the Gulf Coast at Mont Belvieu, Texas. The facility has a capacity of approximately 145 MBbls/d.
  - *Bridgeport and East Johnson County gathering systems*. The Bridgeport and East Johnson County gathering systems, which are owned by Midstream Holdings, are comprised of three natural gas gathering systems in the Barnett Shale, consisting of an aggregate of approximately 3,010 miles of gathering lines with an aggregate capacity of approximately 1.4 Bcf/d. These gathering systems had an aggregate average throughput of approximately 1,359,700 MMBtu/d for the year ended December 31, 2013.
  - *Silver Creek gathering systems*. Our Silver Creek gathering systems consists of approximately 715 miles of gathering lines that have a total capacity of approximately 1.1 Bcf/d, with average throughput of approximately 700,000 MMBtu/d for the year ended December 31, 2013.
  - *Howard Energy Partners*. Howard Energy Partners, or HEP, owns and operates over 500 miles of pipeline and a 200 MMcf/d processing plant, serving production from the Eagle Ford, Escondido, Olmos, Pearsall and other formations in south Texas. HEP's system has 145 MMcf/d of amine treating capacity and more than 9,000 horsepower of compression. As of December 31, 2013, we owned a 30.6% interest in HEP.
- *Oklahoma*. Our Oklahoma assets consist of processing facilities with a total processing capacity of approximately 550 MMcf/d and gathering systems with total capacity of approximately 605 MMcf/d. All of our Oklahoma assets are owned by Midstream Holdings and are comprised of the following:
  - *Cana System*. The Cana system is a natural gas gathering and processing system located in the Cana-Woodford Shale in West Central Oklahoma. The Cana system includes a 350 MMcf/d processing facility. The Cana system also consists of approximately 413 miles of gathering lines that have a total capacity of approximately 530 MMcf/d and had an average throughput of approximately 320,700 MMBtu/d for the year ended December 31, 2013.
  - *Northridge System*. The Northridge system is a natural gas gathering and processing system located in the Arkoma-Woodford Shale in Southeastern Oklahoma. The Northridge system includes a 200 MMcf/d processing facility. The Northridge system also consists of approximately 140 miles of gathering lines that have a total capacity of approximately 75 MMcf/d and had an average throughput of approximately 69,200 MMBtu/d for the year ended December 31, 2013.
- *Louisiana*. Our Louisiana assets consist of transmission pipelines with a capacity of approximately 2.0 Bcf/d, processing facilities with a total processing capacity of approximately 1.7 Bcf/d and gathering systems with total capacity of approximately 510 MMcf/d. Our Louisiana assets are as follows:
  - *LIG Assets*. The LIG system includes gathering and transmission systems with total capacity of approximately 2.0 Bcf/d, processing facilities with a total processing capacity of approximately 335 MMcf/d and fractionation facilities with total capacity of 10,800 Bbls/d.
    - Our LIG gathering and transmission pipeline system is one of the largest intrastate pipeline systems in Louisiana, consisting of approximately 2,000 miles of mainly transmission pipelines extending from

the Haynesville Shale in north Louisiana to onshore production in south central and southeast Louisiana, which have approximately 2.0 Bcf/d of capacity. Average throughput on the LIG pipeline system was approximately 473,000 MMBtu/d for the year ended December 31, 2013.

- The LIG system also includes two processing facilities with a total processing capacity of 335 MMcf/d. Average throughput on the LIG processing facilities was 255,000 MMBtu/d for the year ended December 31, 2013.

- The Plaquemine plant forming part of our LIG system has a fractionation capacity of 10,800 Bbls/d of raw-make NGL products, and total volume for fractionated liquids at Plaquemine averaged approximately 4,800 Bbls/d for the year ended December 31, 2013.

- *South Louisiana Processing and NGL Assets.* Our south Louisiana natural gas processing and NGL assets include 570 miles of liquids transport lines, approximately 1.4 Bcf/d of processing capacity and 3.1 million barrels of underground NGL storage.

  - *Cajun-Sibon Pipeline System.* Currently, the Cajun-Sibon pipeline system consists of approximately 570 miles of raw make NGL pipelines with a current system capacity of approximately 70,000 Bbls/d. Average throughput on the Cajun-Sibon system was approximately 28,500 Bbls/d for the fourth quarter of 2013 when the new expanded pipeline commenced operation.

  - *Processing Facilities*. Our processing facilities in south Louisiana include three gas processing plants with total processing capacity of 1.4 Bcf/d and throughput that averaged 399,000 MMBtu/d for the year ended December 31, 2013. We also have two fractionation facilities that have a capacity of 83,000 Bbls/d with throughput that averaged 27,300 Bbls/d for the year ended December 31, 2013.

  - *Napoleonville Storage Facility.* The Napoleonville NGL storage facility is connected to our Riverside facility and has a total capacity of 3.1 million barrels of underground storage comprised of two existing caverns.

- *Ohio River Valley.* Our Ohio River Valley operations are an integrated network of assets comprised of a 4,500-barrel-per-hour crude oil and condensate barge loading terminal on the Ohio River, a 20-spot operation crude oil and condensate rail loading terminal on the Ohio Central Railroad network and approximately 200 miles of crude oil and condensate pipelines in Ohio and West Virginia. The assets also include 500,000 barrels of above ground storage and a trucking fleet of approximately 100 vehicles comprised of both semi and straight trucks. We have eight existing brine disposal wells with an injection capacity of approximately 10,000 Bbls/d. We currently hold one additional brine well permit in Ohio.

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. As of December 31, 2013, Devon had a total equity market capitalization of over $25 billion and an investment-grade credit rating.

Pursuant to various gathering and processing agreements, Devon has dedicated approximately 795,000 net acres to Midstream Holdings. Please read "—Midstream Holdings' Contractual Relationship with Devon" below. Devon had approximately 2.2 BBoe of proved reserves in the U.S. as of December 31, 2013, of which approximately 1.2 BBoe, or 55%, was associated with this dedicated acreage. For the year ended December 31, 2013, Devon's average U.S. production was 517 MBoe/d, with approximately 240 MBoe/d, or 46%, associated with this dedicated acreage.

Devon is the largest natural gas producer in the Barnett and Cana-Woodford Shales, the largest NGL producer in the Barnett Shale and one of the largest NGL producers in the Cana-Woodford Shale. In 2013, Devon drilled 172 gross wells in the Barnett Shale with exploration and production capital expenditures of $530 million and drilled 118 gross wells in the Cana-Woodford Shale with exploration and production capital expenditures of approximately $560 million. As of December 31, 2013, Devon held 610,000 net acres in the Barnett Shale, 245,000 net acres in the Cana-Woodford Shale and 40,000 net acres in the Arkoma-Woodford Shale. Devon has drilled over 5,000 gross wells in the Barnett Shale since 2002 and in 2014 expects to drill approximately 90 gross wells with budgeted exploration and production capital expenditures of

approximately $250 million. In the Cana-Woodford Shale, Devon expects to drill approximately 65 gross wells in 2014 with budgeted exploration and production capital expenditures of approximately $150 million. In addition to its current drilling schedule, Devon has identified thousands of additional drilling locations in each of these areas.

Our Business Strategies

Our primary business objectives are to have sustained growth in partnership distributions and to maintain a strong balance sheet. We intend to accomplish these objectives by executing the following strategies:

- *Organic Growth: pursue opportunities around our existing footprint* We expect to grow certain of our systems organically over time by meeting Devon's and our other customers' midstream service needs that result from their drilling activity in our areas of operation. We continually evaluate economically attractive organic expansion opportunities in existing or new areas of operation that allow us to leverage our existing infrastructure, operating expertise and customer relationships by constructing and expanding systems to meet new or increased demand for our services.

- *Dropdowns: maximize opportunities provided by Devon's sponsorship and assets held by ENLC* We plan to execute our growth in part through pursuing accretive dropdown opportunities from Devon and ENLC. We expect to be given the opportunity over time to purchase the remaining 50% interest in Midstream Holdings held by ENLC. We are a party to a preferential rights agreement with ENLC and CEI pursuant to which ENLC and CEI granted us a right of first refusal, for a period of 10 years, with respect to (i) CEI's interest in the E2 companies, services companies focused on the Utica Shale play in the Ohio River Valley that are majority owned by CEI, and (ii) Devon's 50% interest in the Access Pipeline transportation system, to the extent ENLC in the future obtains such interest pursuant to a first offer agreement between Devon and ENLC. We also believe there will continue to be significant opportunities as Devon continues to develop its oil and gas production. However, we cannot be certain that these opportunities will be made available to us, or that we will choose to pursue any such opportunity.

- *Acquisitions: pursue strategic and accretive acquisitions.* We pursue strategic and accretive acquisition opportunities within the midstream energy industry, both in new and existing lines of business, and geographic areas of operation.

- *Strong Balance Sheet: maintain an investment grade quality financial profile.* We intend to maintain appropriate leverage and distribution coverage levels in line with other partnerships in our sector that have received investment grade credit ratings. By maintaining an investment grade quality financial profile, we believe that we will be able to pursue strategic acquisitions and large growth projects at a lower cost of capital, which enhances our competitiveness.

Our Competitive Strengths

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

· *Devon's sponsorship*. We expect our relationship with Devon will continue to provide us with significant business opportunities. Devon is one of the largest independent oil and gas producers in North America. Devon has a significant interest in promoting the success of our business, due to its approximate 70% ownership interest in ENLC and approximate 53% ownership interest in us.

· *Strategically-located assets*. Our assets are strategically located in areas with the potential for increasing throughput volume and cash flow generation. Our asset portfolio includes gathering and processing systems located in areas in which producer activity is focused on crude oil, condensate and NGLs. We estimate that these liquids-focused production areas will generate approximately 75% of our 2014 gross operating margin. Due to the relatively high current price of crude oil and condensate as compared to natural gas, production in these areas offers our customers higher margins and superior economics compared to basins in which the gas is relatively dry. This pricing environment offers expansion opportunities for certain of our systems as producers attempt to increase their rich gas, crude oil and condensate production.

· *Stable cash flows*. Approximately 95% of our cash flows are expected to be derived from fee-based services with no direct commodity exposure. Midstream Holdings has entered into 10-year, fixed-fee gathering and processing agreements with a subsidiary of Devon pursuant to which Midstream Holdings or its subsidiary will provide gathering, treating, compression, dehydration, stabilization, processing and fractionation services, as applicable, for natural gas delivered by Devon to Midstream Holdings' gathering and processing systems in the Barnett, Cana-Woodford

and Arkoma-Woodford Shales. These agreements provide Midstream Holdings with dedication of all of the natural gas owned or controlled by Devon and produced from or attributable to existing and future wells located on certain oil, natural gas and mineral leases covering lands within the acreage dedications, excluding properties previously dedicated to other natural gas gathering systems not owned and operated by Devon. These agreements also include five-year minimum volume commitments and annual rate escalators. Please read "—Midstream Holdings' Contractual Relationship with Devon." We will continue to focus on contract structures that reduce volatility and support long-term stability of cash flows.

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

· *Financial flexibility to pursue expansion and acquisition opportunities*. We believe our stable cash flows, strong balance sheet and access to debt and equity capital markets provide us with the financial flexibility to competitively pursue acquisition and expansion opportunities and to execute our strategy across capital market cycles.

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

We believe that we will leverage our competitive strengths to successfully implement our strategy; however, our business involves numerous risks and uncertainties that may prevent us from achieving our primary business objective. For a more complete description of the risks associated with our business, please see "Exhibit 99.2 Risk Factors."

Midstream Holdings' Contractual Relationship with Devon

Upon the consummation of the business combination, Midstream Holdings entered into a 10-year transportation contract with Devon for the Acacia transmission system as well as the following additional fee-based agreements with Devon:

Contract	Contract Term (Years)	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	850	650	5	CPI
East Johnson County gathering contract	10	125	—	5	CPI
Northridge gathering and processing contract	10	40	40	5	CPI
Cana gathering and processing contract	10	330	330	5	CPI

(1) The Bridgeport gathering and processing contract includes volume commitments to the Bridgeport processing facility as well as the Bridgeport gathering systems.

Recent Growth Developments

Cajun-Sibon Phases I and II. In Louisiana, we are transforming our business that historically has been focused on processing offshore natural gas to a business that is focused on NGLs with additional opportunities for growth from new onshore supplies of NGLs. The Louisiana petrochemical market historically has relied on liquids from offshore production; however, the decrease in offshore production and increase in onshore rich gas production have changed the market structure. Cajun-Sibon Phases I and II will work to bridge the gap between supply, which aggregates in the Mont Belvieu area, and demand, located in the Mississippi River corridor of Louisiana, thereby building a strategic NGL position in this region.

We began this transformation by restarting our Eunice fractionator during 2011 at a rate of 15,000 Bbls/d of NGLs. We expanded the Eunice fractionator to a rate of 55,000 Bbls/d with Cajun-Sibon Phase I ("Phase I"). Phase I of our pipeline

extension project was completed in November 2013 and connects Mont Belvieu supply lines in east Texas to Eunice, providing a direct link to our fractionators in south Louisiana markets. The Phase I Eunice fractionator expansion, which also was completed in early November 2013, has increased our interconnected fractionation capacity in Louisiana to approximately 97,000 Bbls/d of raw-make NGLs.

The Phase I expansion added 130-miles of 12-inch diameter pipeline to our existing 440-mile Cajun-Sibon NGL pipeline system, connecting Mont Belvieu to our

Eunice fractionator. Phase I of the pipeline currently has a capacity of 70,000 Bbls/d for raw make NGLs. The Phase I NGL pipeline extension originates from interconnects with major Mont Belvieu supply pipelines and provides connections for NGLs from the Permian Basin, Barnett Shale, Eagle Ford and other areas to our NGL fractionation facilities and key NGL markets in south Louisiana. Phase I is anchored by a five-year ethane sales agreement with Williams Olefins, a subsidiary of the Williams Companies and a five year natural gasoline sales agreement with another company. We have entered into yearly sales agreements for all other purity products.

We have commenced construction of Cajun-Sibon Phase II which will further enhance our Louisiana NGL business with significant additions to the Cajun-Sibon Phase I infrastructure including further fractionation expansion. Phase II will include the addition of four pumping stations, totaling 13,400 horsepower, that will facilitate increasing NGL supply capacity from Phase I's 70,000 Bbls/d to 120,000 Bbls/d; the construction of a new 100,000 Bbls/d fractionator at the Plaquemine gas processing plant site; the conversion of our Riverside fractionator to a butane-and-heavier facility; and the construction of 57 miles of NGL pipeline that will originate at the Eunice fractionator and connect to the new Plaquemine fractionator, which will provide optionality to move purity products around the Louisiana-liquids market. We will also construct a 32-mile, 16-inch diameter extension of LIG's Bayou Jack lateral, which will provide gas services to customers in the Mississippi River corridor, replacing the conversion of supply lines that we currently use for liquid service. We expect Phase II will be in service during the second half of 2014.

Phase II is anchored by 10-year sales agreements with Dow Hydrocarbons and Resources, or Dow, to deliver up to 40,000 Bbls/d of ethane and 25,000 Bbls/d of propane produced at our new Plaquemine fractionator into Dow's Louisiana pipeline system. We will also deliver 70,000 MMBtu/d of natural gas to Dow's Plaquemine facility.

We believe the Cajun-Sibon project not only represents a tremendous growth step by leveraging our Louisiana assets, but that it also creates a significant platform for continued growth of our NGL business. We believe this project, along with our existing assets, will provide a number of additional opportunities to grow this business, including expanding market optionality and connectivity, upgrading products, expanding rail imports, exporting NGLs and expanding fractionation and product storage capacity.

Bearkat Natural Gas Gathering and Processing System. In the fourth quarter of 2013, we commenced construction of a new natural gas processing complex and rich gas gathering pipeline system in the Permian Basin. The initial construction included treating, processing and gas takeaway solutions for regional producers. The project, which will be fully owned by us, is supported by a 10-year, fee-based contract.

The new-build processing complex, called Bearkat, will be strategically located near our existing Deadwood joint venture assets in Glasscock County, Texas. The processing plant will have an initial capacity of 60 MMcf/d, increasing the Partnership's total operated processing capacity in the Permian to approximately 115 MMcf/d. We will also construct a 30-mile high-pressure gathering system upstream of the Bearkat complex to provide additional gathering capacity for producers in Glasscock and Reagan Counties.

Additionally, in February 2014, we entered into an agreement to construct a new 35-mile, 12-inch diameter high-pressure pipeline that will provide critical gathering capacity for the Bearkat natural gas processing complex. The pipeline will have a capacity of approximately 100 MMcf/d and will provide gas takeaway solutions for constrained producer customers in Howard, Martin and Glasscock counties. The entire project is expected to be completed in the second half of 2014.

Riverside Crude Facility Expansion. In June 2013, we completed the Phase II expansion of our Riverside facility located on the Mississippi River in southern Louisiana. The Riverside facility's capacity to transload crude oil and condensate from railcars to our barge facility increased to approximately 15,000 Bbls/d of crude oil and condensate. Phase II additions to the Riverside facility include a 100,000 barrel above-ground crude oil and condensate storage tank, a rail spur with a 26-spot crude oil and condensate railcar unloading rack and a crude offloading facility with pumps and metering as well as a truck unloading bay. As part of the Phase II expansion, the Riverside facility was modified so that sour crude can be unloaded in addition to sweet crude.

Our Assets

Our assets consist of gathering systems and transmission pipelines, processing and fractionation facilities, storage facilities and ancillary assets. The following tables provide information about our assets as of and for the year ended December 31, 2013:

Gathering and Transmission Pipelines	Approximate Length (Miles)	Compression(1) (HP)	Year Ended December 31, 2013 Estimated Capacity (MMcf/d)	Year Ended December 31, 2013 Average Throughput (Thousands of MMBtu/d)
Texas Assets:				
Partnership Assets†	855	131,834	1,475	1,042,000
Midstream Holdings Assets*	3,132	261,266	2,330	2,101,500
Oklahoma Assets:				
Cana System*	413	92,499	530	320,700
Northridge System*	140	17,895	75	69,200
Louisiana Assets:				
LIG System†	1,925	83,378	1,965	473,000
South Louisiana Assets†	570	—	—[a]	—[b]
Total	7,035	586,872	6,375	4,006,400

† Assets wholly-owned by us.

* Assets owned by Midstream Holdings, in which the Partnership holds a 50% interest as ofMarch 7, 2014.

(1) Includes power generation units.

[a] Estimated capacity for South Louisiana liquid pipeline transportation is 70 MBbls/d.

[b] Average throughput on the expanded Cajun-Sibon pipeline, which commenced operations in October 2013, was 28,500 Bbls/d for the fourth quarter of 2013.

Processing Facilities	Processing Capacity (MMcf/d)	Year Ended December 31, 2013 Average Throughput (MMBtu/d)
Texas Assets		
Partnership Assets†	314	349,000

Midstream Holdings Assets*	790	810,600
Oklahoma Assets		
Cana System*	350	278,700
Northridge System*	200	121,000
Louisiana Assets		
LIG Assets†	335	255,000
South Louisiana Assets†	1,375	399,000
Total	3,364	2,213,300

† Assets wholly-owned by us.

* Assets owned by Midstream Holdings, in which the Partnership holds a 50% interest as ofMarch 7, 2014.

Fractionation Facilities	Estimated NGL Fractionation Capacity (MBbls/d)	Average Throughput (MBbls/d)
Texas Assets		
Partnership Assets†	15	—(2)
Midstream Holdings Assets*	15	—(2)
Louisiana Assets		
LIG Assets†	11	5
South Louisiana Assets†	83	27
Gulf Coast Fractionators(1)	56	44
Total	180	76

† Assets wholly-owned by us.

* Assets owned by Midstream Holdings, in which the Partnership holds a 50% interest as ofMarch 7, 2014.

(1) Volumes are shown net to Midstream Holdings' net contractual right to the burdens and benefits of a 38.75% economic interest in Gulf Coast Fractionators held by Devon.

(2) Our Texas Partnership fractionation facility is connected to our Deadwood processing plant in the Permian Basin and the Midstream Holdings fractionation facility is connected to our Bridgeport processing plant. These fractionation facilities provide operational flexibility for the related processing plants, but are not the primary fractionation facilities for the NGLs produced by the processing plants. Under our current contracts, we do not earn fractionation fees for operating these fractionation facilities so throughput volumes through these facilities are not captured on a routine basis and are not significant to our operating margins.

Texas Assets. Our Texas assets consist of systems and other assets in which our interest is held through our wholly-owned subsidiaries as well as systems and other assets owned by Midstream Holdings, in which we own a 50% interest, and include transmission pipelines with a capacity of approximately 1.3 Bcf/d, processing facilities with a total processing capacity of approximately 1.1 Bcf/d and gathering systems with total capacity of approximately2.5 Bcf/d.

- *Transmission Systems*. Our transmission systems in Texas include approximately 260 miles of pipeline with an aggregate capacity of approximately1.3 Bcf/d and consist of the following:

  - *North Texas Pipeline.* Our North Texas Pipeline ("NTPL"), is a 140-mile pipeline extending from an area near Fort Worth, Texas to a point near Paris, Texas and connects production from the Barnett Shale to markets in north Texas accessed by the Natural Gas Pipeline Company of America, LLC, Kinder Morgan, Inc., Houston Pipeline Company, L.P., Atmos Energy Corporation and Gulf Crossing Pipeline Company, LLC. The NTPL has approximately 375 MMcf/d of capacity and 18,960 horsepower of compression and, for the year ended December 31, 2013, the average throughput on the NTPL was approximately 342,000 MMBtu/d.

  - *Acacia transmission system.* The Acacia transmission system, which is owned by Midstream Holdings, is a 120-mile pipeline that connects production from the Barnett Shale to markets in north Texas accessed by Atmos Energy, Brazos Electric, Enbridge Energy Partners, Energy Transfer Partners, Enterprise Product Partners and GDF Suez. The Acacia transmission system has approximately 920 MMcf/d of capacity and 17,000 horsepower of compression and, for the year ended December 31, 2013, average throughput was approximately 741,800 MMBtu/d. Devon is the Acacia transmission system's only customer and has entered into a 10-year transportation agreement that covers transmission services on the Acacia transmission pipeline and includes annual rate escalators.

- *Processing Facilities*. Our processing facilities in Texas include five gas processing plants with total processing throughput that averaged 1,159,600 MMBtu/d for the year ended December 31, 2013 and consist of the following:

  - *Bridgeport processing facility.* Our Bridgeport natural gas processing facility, located in Wise County, Texas, approximately 40 miles northwest of Fort Worth, Texas, is owned by Midstream Holdings and is one of the largest processing plants in the U.S. with seven cryogenic turboexpander plants that have an

aggregate of 790 MMcf/d of processing capacity and 15 MBbls/d of NGL fractionation capacity. For the year ended December 31, 2013, throughput volumes at the Bridgeport processing facility averaged 810,600 MMBtu/d of natural gas. Devon is the Bridgeport facility's largest customer with approximately 744,600 MMBtu/d of natural gas processed for the year ended December 31, 2013, which represented approximately 92% of the total volumes processed at the facility during such period. Devon and Midstream Holdings have entered into a 10-year, fixed-fee gathering and processing agreement pursuant to which Midstream Holdings will provide processing services for natural gas delivered by Devon to the Bridgeport processing facility. This contractual arrangement includes a five-year minimum volume commitment from Devon of 650 MMcf/d of natural gas delivered to the Bridgeport processing facility as well as annual rate escalators.

  - *Silver Creek processing complex.* Our Silver Creek processing complex, located in Weatherford, Azle and Fort Worth, Texas, includes three processing plants. Our Silver Creek plants have a total of 285 MMcf/d of processing capacity, with the Azle Plant, Silver Creek Plant and Goforth Plant accounting for

50 MMcf/d, 200 MMcf/d and 35 MMCf/d of processing capacity, respectively. For the year ended December 31, 2013, throughput volumes at the Silver Creek processing facility averaged 316,000 MMBtu/d of natural gas.

- *Permian Basin assets*. Our Permian Basin assets consist of our Deadwood natural gas processing plant and our Mesquite Terminal fractionator. We have a 50% undivided working interest in the Deadwood processing facility which is located in Glasscock County, Texas. The Deadwood plant is supported by acreage dedication from a major producer in the Permian Basin. The Deadwood processing facility has a total capacity of 58 MMcf/d and total processing throughput that averaged 66,000 MMBtu/d for the year ended December 31, 2013. The Mesquite Terminal, which has 15,000 BBls/d of fractionation capacity, is located in Midland County and serves as a terminal for third party raw-make NGLs. We are also transloading crude oil and condensate at this facility.

- *Gulf Coast Fractionators.* Midstream Holdings is entitled to receive the economic benefits and burdens of the 38.75% interest in Gulf Coast Fractionators held by Devon, with the remaining interests owned 22.50% by Phillips 66 and 38.75% by Targa Resources Partners. Gulf Coast Fractionators owns an NGL fractionator located on the Gulf Coast at Mont Belvieu, Texas. Phillips 66 is the operator of the fractionator. Gulf Coast Fractionators 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. For the year ended December 31, 2013, Gulf Coast Fractionators contributed $14.8 million of income on equity investments, on a pro forma basis giving effect to the business combination.

- *Gathering Systems.* Our gathering systems in Texas include approximately 3,725 miles of pipeline with total throughput of approximately2,059,700 MMBtu/d and consist of the following:

  - *Bridgeport rich gathering system*. This rich natural gas gathering system, which is owned by Midstream Holdings, consists of approximately 2,440 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. Devon is the largest customer on the Bridgeport rich gathering system with approximately 792,000 MMBtu/d of natural gas gathered for the year ended December 31, 2013, which represented approximately 92% of the total throughput on the system during such period. As described above, Devon and Midstream Holdings have entered into a 10-year, fixed-fee gathering and processing agreement pursuant to which Midstream Holdings will provide gathering services on the Bridgeport system, which includes a five-year minimum volume commitment from Devon of a combined 850 MMcf/d of natural gas delivered for gathering into the Bridgeport rich and Bridgeport lean gathering systems.

  - *Bridgeport lean gathering system*. This lean natural gas gathering system, which is owned by Midstream Holdings, consists of approximately 300 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. Devon is the largest customer on the Bridgeport lean gathering system with approximately 256,600 MMBtu/d of natural gas gathered for the year ended December 31, 2013, which represented approximately 98% of the total throughput on the system during such period. As described above, Devon and Midstream Holdings have entered into a 10-year, fixed-fee gathering and processing agreement that covers gathering services on the Bridgeport system.

  - *East Johnson County gathering system*. This natural gas gathering system, which is owned by Midstream Holdings, consists of approximately 270 miles of pipeline segments. Natural gas gathered on this system is delivered to intrastate pipelines without processing. Devon is the largest customer on the East Johnson County gathering system with approximately 220,200 MMBtu/d of natural gas gathered for the year ended December 31, 2013, which represented approximately 93% of the total throughput on the system during such period. Devon and Midstream Holdings have entered into a 10-year, fixed-fee gathering agreement pursuant to which Midstream Holdings will provide gathering services on the East Johnson County gathering system, which includes a five-year minimum volume commitment from Devon of 125 MMcf/d of natural gas delivered for gathering into the East Johnson County gathering system as well as annual rate escalators.

  - *Silver Creek gathering systems*. Our Silver Creek gathering systems includes two gathering systems. Our north Texas gathering system, which we refer to as NTG, consists of approximately 680 miles of gathering lines with approximately 112,874 horsepower of compression and had an average throughput of approximately 690,000 MMBtu/d for the year ended December 31, 2013. The Denton system consists of approximately 35 miles of gathering lines and had an average throughput of approximately 10,000 MMBtu/d for the year ended December 31, 2013.

- *Howard Energy Partners*. HEP owns and operates over 500 miles of pipeline and a 200 MMcf/d processing plant, serving production from the Eagle Ford, Escondido, Olmos, Pearsall and other formations in south Texas and pursues a growth strategy focused on the needs of south Texas producers. Howard's system has 145 MMcf/d of amine treating capacity and more than 9,000 horsepower of compression. In 2011 and 2012, we made capital contributions totaling $87.3 million to HEP in exchange for an individual ownership interest in HEP. As of December 31, 2013, we owned a 30.6% interest in HEP and accounted for this investment under the equity method of accounting. We include our equity investment in HEP in our corporate segment. In December 2013, Alinda Capital Partners acquired a 59% capital interest in HEP from Quanta Capital Solutions and GE Energy Financial Services. We contributed an additional $30.6 million to HEP during the year ended December 31, 2013 to fund our 30.6% share of HEP's expansion costs. We also received cash distributions totaling $17.5 million from HEP during the year ended December 31, 2013.

Oklahoma Assets. Our Oklahoma assets consist of processing facilities with a total processing capacity of approximately550 MMcf/d, gathering systems with total capacity of approximately 605 MMcf/d and a crude oil and condensate stabilization facility. All of the systems and other assets comprising our Oklahoma assets are owned by Midstream Holdings, in which we own a 50% interest.

- *Cana system*. Our Cana gathering and processing system is located in the Cana-Woodford Shale in West Central Oklahoma and consists of the following:

  - *Cana processing facilities.* Our Cana processing facilities include a multi-train 350 MMcf/d cryogenic processing plant and a crude oil and condensate stabilization facility. For the year ended December 31, 2013, throughput volumes at the Cana processing facility averaged 278,700 MMBtu/d. The residue natural gas from the Cana processing facility is delivered to Enable Midstream Partners and ONEOK Partners. Devon is the only customer of the Cana processing facilities and has entered into a 10-year, fixed-fee gathering and processing agreement with Midstream Holdings pursuant to which Midstream Holdings will provide processing services for natural gas delivered by Devon to the Cana processing facility. This contractual arrangement includes a five-year minimum volume commitment from Devon of 330 MMcf/d of natural gas delivered to the processing facility as well as annual rate escalators.

  - *Cana gathering system*. Our Cana gathering system includes an approximately 410-mile gathering system with approximately 92,500 horsepower of compression. For the year ended December 31, 2013, the Cana system gathered approximately 320,700 MMBtu/d of gas. Devon is the only customer of the Cana gathering system and, as described above, has entered into a 10-year, fixed-fee gathering and processing agreement with Midstream Holdings pursuant to which Midstream Holdings will provide gathering services on the Cana gathering system and that includes a five-year minimum volume commitment from Devon of 330 MMcf/d of natural gas delivered for gathering into the Cana gathering system.

- *Northridge system*. Our Cana gathering and processing system is located in the Arkoma-Woodford Shale in Southeastern Oklahoma and consists of the following:

- *Northridge processing plant.* Our Northridge processing plant has 200 MMcf/d of processing capacity. For the year ended December 31, 2013, throughput volumes at the Northridge processing facility averaged 121,000 MMBtu/d. The residue natural gas from the Northridge processing facility is delivered to Centerpoint, Enable Midstream Partners and MarkWest. Devon is the largest customer of the Northridge processing facility with approximately 63,900 MMBtu/d of natural gas processed for the year ended December 31, 2013, which represented approximately53% of the total volumes processed at the facility during such period. Devon has entered into a 10-year fixed-fee gathering and processing agreement with Midstream Holdings pursuant to which Midstream Holdings will provide processing services for natural gas delivered by Devon to the Northridge processing facility. This contractual arrangement includes a five-year minimum volume commitment of 40 MMcf/d of natural gas delivered to the Northridge processing facility as well as annual rate escalators.

- *Northridge gathering system*. Our Northridge gathering system includes an approximate 140-mile gathering system with approximately 17,900 horsepower of compression. For the year ended December 31, 2013, the Northridge system gathered 69,200 MMBtu/d of gas. Northridge gathered volumes exclude approximately 40 MMcf/d delivered by third parties directly to the processing facility. Devon is the only customer on the Northridge gathering system and, as described above, has entered into a 10-year fixed-fee gathering and processing agreement with Midstream Holdings pursuant to which Midstream Holdings will provide gathering services on the Northridge gathering system. This contract includes a five-year minimum volume commitment from Devon of 40 MMcf/d of natural gas delivered for gathering into the Northridge gathering system.

Louisiana Assets. Our Louisiana assets consist of transmission pipelines with a capacity of approximately2.0 Bcf/d, processing facilities with a total processing capacity of approximately 1.7 Bcf/d and gathering systems with total capacity of approximately510 MMcf/d.

- *LIG Assets.* The LIG system includes gathering and transmission systems with total capacity of approximately 2.0 Bcf/d, processing facilities with a total processing capacity of approximately 335 MMcf/d and fractionation facilities with total capacity of 10,800 Bbls/d.

  - The LIG gathering and transmission pipeline system is comprised of the 1,125-mile southern system, which has a capacity in excess of 1.5 Bcf/d and approximately 31,318 horsepower of compression, and the 800-mile northern system, which has a capacity of 465 MMcf/d and approximately 52,060 horsepower of compression. The south system has access to both rich and lean gas supplies from onshore production in south central and southeast Louisiana. LIG has a variety of transportation and industrial sales customers in the south, with the majority of its sales being made into the industrial Mississippi River corridor between Baton Rouge and New Orleans. In the north, the LIG system serves the natural gas fields south of Shreveport, Louisiana and extends into the Haynesville Shale gas play in north Louisiana. Our north Louisiana system is connected to our south Louisiana system and has the capacity to move approximately 145 MMcf/d of gas to our markets in the south. Our LIG gathering system had an average throughput of approximately 473,000 MMbtu/d for the year ended December 31, 2013.

  - The south system also includes two operating, on-system processing plants, our Gibson and Plaquemine plants, with 110 MMcf/d and 225 MMcf/d of processing capacity, respectively. For the year ended December 31, 2013, throughput volumes on our LIG processing system averaged 255,000 MMBtu/d of natural gas.

  - The Plaquemine plant also has a fractionation capacity of 10,800 Bbls/d of raw-make NGL products, and total volume for fractionated liquids at Plaquemine averaged approximately 4,800 Bbls/d for the year ended December 31, 2013.

- *South Louisiana NGL and Processing Assets.* Our south Louisiana NGL and natural gas processing assets include approximately 570 miles of liquids transport lines, processing and fractionation capabilities and underground storage.

  - *Cajun-Sibon Pipeline System.* Currently, the Cajun-Sibon pipeline system consists of approximately 570 miles of raw make NGL pipelines with a current system capacity of approximately 70,000 Bbls/d. The pipelines transport unfractionated NGLs, referred to as raw make, from areas such as the Liberty, Texas interconnects near Mont Belvieu and from our Eunice and Pelican processing plants in south Louisiana to either the Riverside or Eunice fractionators or to third party fractionators when necessary.

  - *Processing Facilities*. Our processing facilities in south Louisiana include three gas processing plants with total processing throughput that averaged 399,000 MMBtu/d for the year ended December 31, 2013 and two fractionation facilities that averaged 27,300 Bbls/d for the year ended December 31, 2013.

    - *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, 2013, the plant processed approximately 334,000 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 LIG pipeline allowing us to process natural gas from the LIG system at our Pelican plant when markets are favorable.

    - *Blue Water Gas Processing Plant.* We own a 64.29% interest in the Blue Water gas processing plant and operate the plant. The Blue Water plant is located in Crowley, Louisiana and is connected to the Blue Water pipeline system. The plant has a net capacity to our interest of approximately 300 MMcf/d. For the year ended December 31, 2013, throughput volumes at the Blue Water gas processing plant averaged 12,600 MMBtu/d of natural gas. 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, has a capacity of 475 MMcf/d ofnatural gas and processed approximately 31,200 MMBtu/d of natural gas for the year ended December 31, 2013. In August 2013, we shut down the Eunice processing plant due to adverse economics driven by low NGL prices and low processing volumes, which we do not see improving in the near future based on forecasted prices.

    - *Eunice Fractionation Facility.* The Eunice fractionation facility is located in south central Louisiana and was restarted in 2011 to take advantage of the activity around liquids rich shale-plays, including the Eagle Ford, Permian, Granite Wash, Marcellus and Utica plays. 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 5,100 Bbls/d of liquids during 2013.

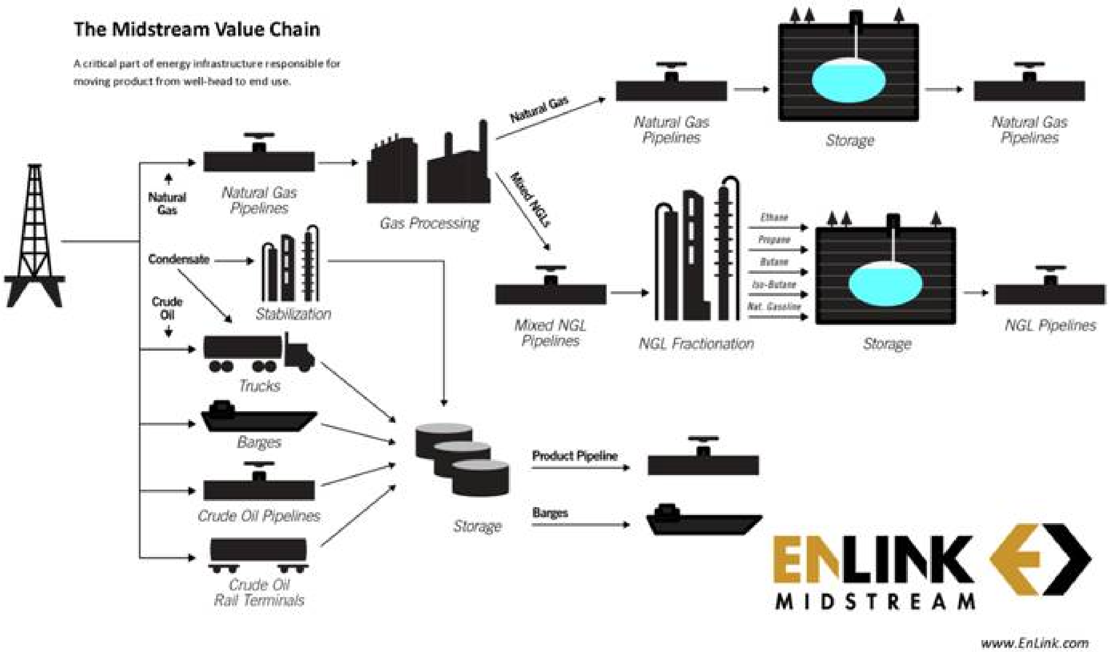
    - *Riverside Fractionation Facility.* The Riverside fractionator and loading facility is located on the Mississippi River upriver from Geismar, Louisiana. The Riverside plant has a fractionation capacity of approximately 28,000 Bbls/d of liquids delivered by the Cajun-Sibon pipeline system from the Eunice, Pelican and Blue Water processing plants or by third-party truck and rail assets. The Riverside facility has above-ground storage capacity of approximately 233,000 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 22,200 Bbls/d for the year ended December 31, 2013.

  - *Napoleonville Storage Facility.* The Napoleonville NGL storage facility is connected to the Riverside facility and has a total capacity of 3.1 million barrels of underground storage comprised of two existing caverns. The caverns are currently operated in propane and butane service, and space is leased to customers for a fee.

Ohio River Valley Assets. Our Ohio River Valley operations are an integrated network of assets comprised of a 4,500-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 200 miles of crude oil and condensate pipelines in Ohio and West Virginia. The assets also include 500,000 barrels of above ground storage and a trucking fleet of approximately 100 vehicles comprised of both semi and straight trucks with a current capacity of 25,000 Bbls/d. Total crude oil and condensate handled averaged approximately 11,000 Bbls/d for the year ended December 31, 2013. We have eight existing brine disposal wells with an injection capacity of approximately 10,000 Bbls/d and an average disposal rate of 7,000 Bbls/d for the year ended December 31, 2013. We currently hold one additional well permit in Ohio.

Industry Overview

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



The midstream industry is the link between the exploration and production of natural gas and crude oiland 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. In contrast, a declining well can continue delivering natural gas if the 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.

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

Crude oil and condensate terminals. Crude oil and condensate rail terminals are an integral part of ensuring the movement of new crude oiland 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 markets via pipelines, trucks or rail to delivery points.

Balancing Supply and Demand

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

Competition

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

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

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

Natural Gas, NGL, Crude Oil and Condensate Supply

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

Credit Risk and Significant Customers

We are diligent in attempting to ensure that we issue credit to only credit-worthy customers. However, our purchase and resale of crude oiland condensate, gas and other products exposes us to significant credit risk, as the margin on any sale is generally a very small percentage of the total sale price. Therefore, a credit loss can be very large relative to our overall profitability.

During the year ended December 31, 2013, Devon represented 24.9% of our consolidated revenues, on a pro forma basis. No other customer represented greater than 10.0% of our revenue. Midstream Holdings' operations are dependent on the volume of natural gas that Devon provides to us under commercial agreements, which constitutes substantially all of their natural gas supply, and we do not expect to materially increase volumes from third-party producers in the near term. Accordingly, for the foreseeable future, we expect our profitability to be substantially dependent on Devon.

Regulation

Interstate Natural Gas Pipelines Regulation. We do not own any interstate natural gas pipelines, so the Federal Energy Regulatory Commission ("FERC"), does not directly regulate our natural gas operations under the National Gas Act ("NGA"). However, FERC's regulation of interstate natural gas pipelines influences certain aspects of our business and the market for our products. In general, FERC has authority over natural gas companies that provide natural gas pipeline transportation services in interstate commerce and its authority to regulate those services includes:

- the certification and construction of new facilities;
- the extension or abandonment of services and facilities;
- the maintenance of accounts and records;

- the acquisition and disposition of facilities;
- maximum rates payable for certain services; and
- the initiation and discontinuation of services.

We transport gas in interstate commerce. The rates, terms and conditions of service under which we transport natural gas in our pipeline systems in interstate commerce are subject to FERC jurisdiction under Section 311 of the Natural Gas Policy Act ("NGPA"). The maximum rates for services provided under Section 311 of the NGPA may not exceed a "fair and equitable rate," as defined in the NGPA. The rates are generally subject to review every three years by FERC or by an appropriate state agency. The inability to obtain approval of rates at acceptable levels could result in refund obligations, the

inability to achieve adequate returns on investments in new facilities and the deterrence of future investment or growth of the regulated facilities.

Interstate Liquids Pipelines Regulation. We own liquids transportation, storage and other assets in the Ohio River Valley, including certain assets providing common carrier interstate service subject to regulation by FERC under the Interstate Commerce Act ("ICA"), the Energy Policy Act of 1992 and related rules and orders. Our Cajun-Sibon NGL pipeline became subject to FERC regulation as a result of our Phase I expansion, which went into operation in November 2013. The expansion is subject to regulation by FERC as a common carrier under the ICA, the Energy Policy Act of 1992 and related rules and orders.

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

Rates of interstate liquids pipelines are currently regulated by FERC primarily through an annual indexing methodology, under which pipelines increase or decrease their rates in accordance with an index adjustment specified by FERC. For the five-year period beginning in 2010, FERC established an annual index adjustment equal to the change in the producer price index for finished goods plus 2.65%. This adjustment is subject to review every five years. Under FERC's regulations, liquids pipelines can request a rate increase that exceeds the rate obtained through application of the indexing methodology by using a cost-of-services approach, but only after the pipeline establishes that a substantial divergence exists between the actual costs experienced by the pipeline and the rates resulting from application of the indexing methodology.

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

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

Intrastate Natural Gas Pipeline Regulation. Our intrastate natural gas pipeline operations are subject to regulation by various agencies of the states in which they are located. Most states have agencies that possess the authority to review and authorize natural gas transportation transactions and the construction, acquisition, abandonment and interconnection of physical facilities. Some states also have state agencies that regulate transportation rates, service terms and conditions and contract pricing to ensure their reasonableness and to ensure that the intrastate pipeline companies that they regulate do not discriminate among similarly situated customers.

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

Gathering Pipeline Regulation. Section 1(b) of the NGA exempts natural gas gathering facilities from the jurisdiction of FERC under the NGA. We own a number of natural gas pipelines that we believe meet the traditional tests FERC has used to establish a pipeline's status as a gatherer not subject to FERC jurisdiction. State regulation of gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements, and in some instances complaint-based rate regulation.

We are subject to some state ratable take and common purchaser statutes. The ratable take statutes generally require gatherers to take, without undue discrimination, natural gas production that may be tendered to the gatherer for handling. Similarly, common purchaser statutes generally require gatherers to purchase without undue discrimination as to source of supply or producer. These statutes are designed to prohibit discrimination in favor of one producer over another producer or one source of supply over another source of supply.

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

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

Environmental Matters

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

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

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

Hazardous Substances and Solid Waste. Environmental laws and regulations that relate to the release of hazardous substances or solid wastes into soils, groundwater and surface water and/or include measures to prevent and control pollution may pose the highest potential cost to our industry sector. These laws and regulations generally regulate the generation, storage, treatment, transportation and disposal of solid and hazardous wastes and may require investigatory and corrective actions at facilities where such waste may have been released or disposed. For instance, the Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA"), also known as the federal "Superfund" law, and comparable state laws impose liability without regard to fault or the legality of the original conduct on certain classes of persons that contributed to a release of a "hazardous substance" into the environment. Potentially liable persons include the owner or operator of the site where a release occurred and companies that disposed or arranged for the disposal of the hazardous substances found at an off-site location, such as a landfill. Under CERCLA, these persons may be subject to joint and several liability for the costs of cleaning up and restoring sites where hazardous substances have been released into the environment and for damages to natural resources. CERCLA also authorizes the U.S. Environmental Protection Agency (EPA) and, in

some cases, third parties to take actions in response to threats to public health or the environment and to seek recovery of costs they incur from the potentially responsible classes of persons. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or solid wastes released into the environment. Although petroleum, natural gas and NGLs are excluded from CERCLA's definition of a "hazardous substance," in the course of ordinary operations, we may generate wastes that may fall within the definition of a "hazardous substance." In addition, there are other laws and regulations that can create liability for releases of petroleum, natural gas or NGLs. Moreover, we may be responsible under CERCLA or other laws for all or part of the costs required to clean up sites at which such substances have been disposed. We have not received any notification that we may be potentially responsible for cleanup costs under CERCLA or any analogous federal or state law.

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

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

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

In addition, the EPA included Wise County in its January 2012 revision to the Dallas-Ft. Worth ozone nonattainment area for the 2008 revised ozone national ambient air quality standard ("NAAQS"). As a result of this designation, new major sources, meaning sources that emit greater than 100 tons/year of nitrogen oxides ("NOx") and volatile organic compounds ("VOCs"), as well as major modifications of existing facilities resulting in net emissions increases of greater than 40 tons/year of NOx or VOCs, are subject to more stringent new source review ("NSR") pre-construction permitting requirements than they would be in an area that is in attainment with the 2008 ozone NAAQS. NSR pre-construction permits can take twelve to eighteen months to obtain and require the permit applicant to offset the proposed emission increases with reductions elsewhere at 1.15 to 1 ratio. Devon, Texas industry trade groups and the State of Texas filed petitions for reconsideration with EPA and a petition for review in the U.S. D.C. Circuit Court of Appeals challenging the nonattainment designation of Wise County under the 2008 ozone NAAQS. The appeal remains pending.

On April 17, 2012, the EPA approved final rules under the Clean Air Act that establish new air emission controls for oil and natural gas production, pipelines and processing operations. These rules became effective on October 15, 2012. For new or reworked hydraulically-fractured gas wells, the rules require the control of emissions through flaring or reduced emission (or "green") completions until 2015, when the rules require the use of green completions by all such wells except wildcat (exploratory) and delineation gas wells and low reservoir pressure non-wildcat and non-delineation gas wells. The rules also establish specific new requirements regarding emissions from wet seal and reciprocating compressors at production facilities, gathering systems, boosting facilities and onshore natural gas processing plants, effective October 15, 2012, and from pneumatic controllers and storage vessels at production facilities, gathering systems, boosting facilities and onshore natural gas processing plants, effective October 15, 2013. In addition, the rules revise existing requirements for volatile organic compound emissions from equipment leaks at onshore natural gas processing plants by lowering the leak definition for valves from 10,000 parts per million to 500 parts per million and requiring the monitoring of connectors, pumps, pressure relief devices and open-ended lines, effective October 15, 2012. These rules required a number of modifications to our assets and operations.

In October 2012, several challenges to the EPA's April 17, 2012 rules 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. EPA issued a final rule revising certain aspects of the rules on August 5, 2013 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. The costs of compliance with any modified or newly issued rules cannot be predicted. Additionally, on December 11, 2012, seven states submitted a notice of intent to sue the EPA to compel the agency to make a determination whether standards of performance limiting methane emissions from the oil and gas sector are appropriate, which was not addressed in the EPA rule took effect on October 15, 2012. The notice of intent also requested that the EPA issue emission guidelines for the control of methane emissions from existing oil and gas sources. Depending on whether such rules are promulgated and the applicability and restrictions in any promulgated rule, 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.

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

Because regulation of greenhouse gas emissions is relatively new, further regulatory, legislative and judicial developments are likely to occur. Such developments in greenhouse gas initiatives may affect us and other companies operating in the oil and gas industry. In addition to these developments, recent judicial decisions have allowed certain tort claims alleging property damage to proceed against greenhouse gas emissions sources, which may increase our litigation risk for such claims. Due to the uncertainties surrounding the regulation of and other risks associated with greenhouse gas emissions, we cannot predict the financial impact of related developments on us.

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

Some scientific studies on climate change suggest that adverse weather events may become stronger or more frequent in the future in certain of the areas in which we operate, although the scientific studies are not unanimous. Due to their location, our operations along the Gulf Coast are vulnerable to operational and structural damages resulting from hurricanes and other severe weather systems, while inland operations include areas subject to tornadoes. Our insurance may

not cover all associated losses. We are taking steps to mitigate physical risks from storms, but no assurance can be given that future storms will not have a material adverse effect on our business.

Hydraulic Fracturing and Wastewater. The Federal Water Pollution Control Act, also known as the Clean Water Act, and comparable state laws impose restrictions and strict controls regarding the discharge of pollutants, including NGL related wastes, into state waters or waters of the United States. Regulations promulgated pursuant to these laws require that entities that discharge into federal and state waters obtain National Pollutant Discharge Elimination System ("NPDES"), and/or state permits authorizing these discharges. The Clean Water Act and analogous state laws assess administrative, civil and criminal penalties for discharges of unauthorized pollutants into the water and impose substantial liability for the costs of removing spills from such waters. In addition, the Clean Water Act and analogous state laws require that individual permits or coverage under general permits be obtained by covered facilities for discharges of storm water runoff. We believe that we are in substantial compliance with Clean Water Act permitting requirements as well as the conditions imposed thereunder and that continued compliance with such existing permit conditions will not have a material effect on our results of operations.

We operate brine disposal wells that are regulated as Class II wells under the federal Safe Drinking Water Act (SDWA). The SDWA imposes requirements on owners and operators of Class II wells through the EPA's Underground Injection Control program, including construction, operating, monitoring and testing, reporting and closure requirements. Our brine disposal wells are also subject to comparable state laws and regulations, which in some cases are more stringent than requirements under the federal SDWA. Compliance with current and future laws and regulations regarding our brine disposal wells may impose substantial costs and restrictions on our brine disposal operations, as well as adversely affect demand for our brine disposal services. State and federal regulatory agencies recently have focused on a possible connection between the operation of injection wells used for oil and gas waste waters and an observed increase in minor seismic activity and tremors. When caused by human activity, such events are called induced seismicity. In a few instances, operators of injection wells in the vicinity of minor seismic events have reduced injection volumes or suspended operations, often voluntarily. A 2012 report published by the National Academy of Sciences concluded that only a very small fraction of the tens of thousands of injection wells have been suspected to be, or have been, the likely cause of induced seismicity. Regulatory agencies are continuing to study possible linkage between injection activity and induced seismicity. To the extent these studies result in additional regulation of injection wells, such regulations could impose additional regulations, costs and restrictions on our brine disposal operations.

It is common for our customers or suppliers to recover natural gas from deep shale formations through the use of hydraulic fracturing, combined with sophisticated horizontal drilling. Hydraulic fracturing is an important and commonly used process in the completion of wells by oil and gas producers. Hydraulic fracturing involves the injection of water, sand and chemical additives under pressure into rock formations to stimulate gas production. Due to public concerns raised regarding potential impacts of hydraulic fracturing on groundwater quality, legislative and regulatory efforts at the federal level and in some states and localities have been initiated to require or make more stringent the permitting and other regulatory requirements for hydraulic fracturing operations. 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. In addition, the EPA is conducting a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater and has initiated plans to promulgate regulations controlling wastewater disposal associated with hydraulic fracturing and shale gas development. These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing. Additional regulatory burdens in the future, whether federal, state or local, could increase the cost of or restrict the ability of our customers or suppliers to perform hydraulic fracturing. As a result, any increased federal, state or local regulation could reduce the volumes of natural gas that our customers move through our gathering systems which would materially adversely affect our revenues and results of operations.

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

Pipeline Safety Regulations. Our pipelines are subject to regulation by the U.S. Department of Transportation (DOT). DOT's Pipeline Hazardous Material Safety Administration (PHMSA), acting through the Office of Pipeline Safety (OPS), administers the national regulatory program to assure the safe transportation of natural gas, petroleum and other hazardous materials by pipeline. OPS develops regulations and other approaches to risk management to assure safety in

design, construction, testing, operation, maintenance and emergency response of pipeline facilities. The main bodies of safety regulations that cover our operations are set forth at 49 CFR, Parts 192 (covering pipelines that transport natural gas) and 195 (pipelines that transport crude oil and condensate, carbon dioxide, NGL and petroleum products). In addition to recordkeeping and reporting requirements, amendments to 49 CFR Part 192 and 195 created the Pipeline Integrity Management in High Consequence Areas (PIM) requiring operators of transmission pipelines to ensure the integrity of their pipelines through hydrostatic pressure testing, the use of in-line inspection tools or through risk-based direct assessment techniques. In January 2012, the President signed into law the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 which increases potential penalties for pipeline safety violations, gives new rulemaking authority to DOT with respect to shut-off valves on transmission pipeline facilities constructed or entirely replaced after the rule is promulgated, requires DOT to revise incident notification guidance and imposes new records requirements on pipeline owners and operators. This legislation also requires DOT to study and report to Congress on other areas of pipeline safety, including expanding the reach of the integrity management regulations beyond high consequences areas, but restricts DOT from promulgating expanded integrity management rules during the review period and for a period following submission of its report to Congress unless the rulemaking is needed to address a present condition that poses a risk to public safety, property or the environment. PHMSA issued a final rule effective October 25, 2013 that implemented aspects of the new legislation. Among other things, the final rule increases the maximum civil penalties for violations of pipeline safety statutes or regulations, broadens PHMSA's authority to submit information requests, and provides additional detail regarding PHMSA's corrective action authority. Additionally, PHMSA issued an Advisory Bulletin in May 2012, which advised pipeline operators of anticipated changes in annual reporting requirements and that if they are relying on design, construction, inspection, testing or other data to determine the pressures at which their pipelines should operate, the records of that data must be traceable, verifiable and complete. Locating such records and, in the absence of any such records, verifying maximum pressures through physical testing or modifying or replacing facilities to meet the demands of such pressures could significantly increase our costs. Additionally, failure to locate such records or verify maximum pressures could result in reductions of allowable operating pressures, which would reduce available capacity on our pipeline. A December 2012 PHMSA Advisory Bulletin provides further clarity on the reporting requirements of the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, describing a general requirement that pipeline owners or operators report an exceedance of the maximum allowable operating pressure or allowable build-up for pressure-limiting or control devices within five days of the date that the exceedance occurs. At the state level, several states have passed legislation or promulgated rulemaking dealing with pipeline safety. We believe that our pipeline operations are in substantial compliance with applicable PHMSA and state requirements; however, due to the possibility of new or amended laws and regulations or reinterpretation of existing laws and regulations, there can be no assurance that future compliance with the PHMSA or state requirements will not have a material adverse effect on our results of operations or financial positions.

Bayou Corne Sinkhole Incident. We own and operate a high-pressure pipeline and underground natural gas and NGL storage reservoirs and associated facilities near Bayou Corne, Louisiana. In August 2012, a large sinkhole formed in the vicinity of these pipelines and our underground storage reservoirs located in Napoleonville, Louisiana.

Following the formation of the sinkhole, we and other pipeline operators in the area promptly undertook steps to depressurize and shut down our pipelines in the affected area. In particular, we took a section of our 36-inch diameter natural gas pipeline out of service. Our pipeline remains out of service, which has partially interrupted service to certain markets including the Mississippi River, but we worked with our customers to secure alternative natural gas supplies to minimize disruptions. In addition, we have identified a reroute for this pipeline outside of the affected areas. We are currently in the initial phase of constructing the replacement pipeline in our rerouted location and anticipate such construction will be completed during first half of 2014. We also implemented additional inspection and operational measures at our nearby underground facility. The damage to our business, including costs and loss of business, has been considerable.

The cause and full consequences of this sinkhole and the conditions giving rise thereto remain uncertain. In addition, any restrictions imposed by governmental agencies could negatively impact our assets. We are assessing the potential for recovering our losses from responsible parties and we are seeking recovery from our insurers. Our insurers, however, have denied our insurance claim for coverage and filed a declaratory judgment asking a court to determine that our insurance policy does not cover this damage. We have sued our insurers for breach of contract due to our insurers' refusal to pay our insurance claim for this damage. We cannot assure you that we will be able to fully recover our losses through insurance recovery or claims against responsible parties.

Office Facilities

We occupy approximately 108,500 square feet of space at our executive offices in Dallas, Texas under a lease expiring in August 2019, approximately 25,100 square feet of office space for our Louisiana operations in Houston, Texas with lease terms expiring in April 2023 and approximately 9,000 square feet of office space in Lafayette, Louisiana with lease terms expiring in January 2023. In connection with the consummation of the business combination, we entered into

three office lease agreements with a wholly-owned subsidiary of Devon pursuant to which we will occupy approximately 12,500 square feet, 2,200 square feet and 4,700 square feet at Devon's Bridgeport, Oklahoma City and Cresson office buildings, respectively. Each lease is scheduled to expire in March 2016.

Employees

As of March 7, 2014, we (through our subsidiaries) employed approximately 1,057 full-time employees. Approximately 245 of our employees were general and administrative, engineering, accounting and commercial personnel and the remainder were operational employees. We are not party to any collective bargaining agreements and we have not had any significant labor disputes in the past. We believe that we have good relations with our employees.

Legal Proceedings

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

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

From time to time, owners of property located near our processing facilities or compression facilities file lawsuits against us. These suits generally allege that the facilities create a private nuisance and have damaged the value of surrounding property. Claims of this nature have arisen as a result of the industrial development of natural gas gathering, processing and treating facilities in urban and occupied rural areas. In January 2012, a plaintiff in one of these lawsuits was awarded a judgment of $2.0 million. We have appealed the matter and have posted a bond to secure the judgment pending its resolution. We have accrued a $2.0 million liability related to this matter. Although it is not possible to predict the ultimate outcomes of these matters, we do not expect that awards in these matters will have a material adverse impact on our consolidated results of operations or financial condition.

Disclosure Regarding Forward-Looking Statements

This report contains forward-looking statements that are based on information currently available to management as well as management's assumptions and beliefs. All statements, other than statements of historical fact, included herein constitute forward-looking statements, including but not limited to statements identified by the words "forecast," "may," "believe," "will," "should," "plan," "predict," "anticipate," "intend," "estimate" and "expect" and similar expressions. Such statements reflect our current views with respect to future events, based on what we believe are reasonable assumptions; however, such statements are subject to certain risks and uncertainties. In addition to the specific uncertainties discussed elsewhere in this report, the risk factors set forth in "Exhibit 99.2 Risk Factors" in this Current Report on Form 8-K may affect our performance and results of operations. Should one or more of these risks or uncertainties materialize, or should underlying assumptions prove incorrect, actual results may differ materially from those in the forward-looking statements. We disclaim any intention or obligation to update or review any forward-looking statements or information, whether as a result of new information, future events or otherwise.

RISK FACTORS

The following risk factors relate to the combined business of EnLink Midstream Partners, LP (formerly known as Crosstex Energy, L.P.) (the "Partnership") following its acquisition of 50% of the outstanding limited partner interests in EnLink Midstream Holdings, LP (formerly known as Devon Midstream Holdings, L.P.) ("Midstream Holdings") and all of the outstanding equity interests in EnLink Midstream Holdings GP, LLC (formerly known as Devon Midstream Holdings GP, LLC), the general partner of Midstream Holdings (the "business combination"). These risk factors could affect our actual results and should be considered carefully when evaluating us. Other risks and uncertainties, in addition to those that are described below, may also impair our business operations. If any of the following risks occur, our business, financial condition or results of operations could be affected materially and adversely. In that case, we may be unable to make distributions to our unitholders and the trading price of our common units could decline. In this discussion, the term "Partnership," as well as the terms "our," "we," "us" and "its," are sometimes used as abbreviated references to EnLink Midstream Partners, LP itself or EnLink Midstream Partners, LP together with its consolidated subsidiaries and the term "Midstream Holdings" is sometimes used to refer to EnLink Midstream Holdings, LP itself or to EnLink Midstream Holdings, LP together with EnLink Midstream Holdings GP, LLC and their subsidiaries.

These risk factors should be read in conjunction with the other detailed information concerning us set forth in our accompanying financial statements and notes set forth in Exhibits 99.4 and 99.5 and contained in "Management's Discussion and Analysis of Financial Condition and Results of Operations" included in Exhibit 99.3.

This report contains forward-looking statements that are based on information currently available to management as well as management's assumptions and beliefs. All statements, other than statements of historical fact, included herein constitute forward-looking statements, including but not limited to statements identified by the words "forecast," "may," "believe," "will," "should," "plan," "predict," "anticipate," "intend," "estimate" and "expect" and similar expressions. Such statements reflect our current views with respect to future events, based on what we believe are reasonable assumptions; however, such statements are subject to certain risks and uncertainties. Should one or more of these risks or uncertainties materialize, or should underlying assumptions prove incorrect, actual results may differ materially from those in the forward-looking statements. We disclaim any intention or obligation to update or review any forward-looking statements or information, whether as a result of new information, future events or otherwise.

We are dependent on Devon Energy Corporation ("Devon") for a substantial portion of the natural gas that we gather, process and transport. After the expiration of the five-year minimum volume commitments from Devon, a material decline in the volumes of natural gas that we gather, process and transport for Devon could result in a material decline in our operating results and cash available for distribution.

We are dependent on Devon for a substantial portion of our natural gas supply. In particular, Midstream Holdings relies on Devon for substantially all of its natural gas supply. For the year ended December 31, 2013, Devon represented 24.9% of our consolidated revenues, on a pro forma basis. In order to minimize volumetric exposure, Midstream Holdings has received five-year minimum volume commitments from Devon at the Bridgeport processing facility, Bridgeport and East Johnson County gathering systems and the Cana and Northridge systems. After the expiration of these five-year minimum volume commitments, a material decline in the volume of natural gas that Midstream Holdings gathers and transports on its systems would result in a material decline in our combined total operating revenues and cash flow. In addition, Devon may determine in the future that drilling activity in areas of operation other than ours is strategically more attractive. A shift in Devon's focus away from our areas of operation could result in reduced throughput on our systems after the five-year minimum volume commitments expire and cause a material decline in our total operating revenues and cash flow.

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

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

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

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

Please see Item 1.A in Devon's Annual Report on Form 10-K for the year ended December 31, 2013 for a full discussion of the risks associated with Devon's business.

Due to our lack of asset diversification, adverse developments in our gathering, transmission, processing, crude oil, condensate, natural gas and NGL services businesses would reduce our ability to make distributions to our unitholders.

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

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

Our revenue-producing operations are geographically concentrated in the Barnett Shale, causing us to be disproportionally exposed to risks associated with regional factors. Specifically, our operations in the Barnett Shale accounted for approximately 28.4% of our revenues on a pro forma basis for the year ended December 31, 2013. The concentration of our operations in these regions also increases exposure to unexpected events that may occur in these regions such as natural disasters or labor difficulties. Any one of these events has the potential to have a relatively significant impact on our operations and growth plans, decrease cash flows, increase operating and capital costs and prevent development within originally anticipated time frames. Any of these risks could have a material adverse effect on our financial condition and results of operations.

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

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

Fluctuations in energy prices can greatly affect production rates and investments by third parties in the development of new oil, condensate and natural gas reserves. Prolonged periods of low commodity prices may put downward pressure on future drilling activity which may result in lower volumes. Tax policy changes or additional regulatory restrictions on development could also have a negative impact on drilling activity, reducing supplies of product available to our systems and assets. Additional governmental regulation of, or delays in issuance of permits for, the offshore exploration and production industry may negatively impact current and future volumes from offshore pipelines supplying our processing plants. We have no control over producers and depend on them to maintain sufficient levels of drilling activity. A material decrease in production or in the level of drilling activity in our principal geographic areas for a prolonged period, as a result of depressed commodity prices or otherwise, likely would have a material adverse effect on our results of operations and financial position.

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

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

- environmental or other governmental regulations;
- weather conditions;
- increases in storage levels of natural gas and NGLs;
- increased use of alternative energy sources;
- decreased demand for natural gas and NGLs;
- fluctuations in commodity prices, including the prices of natural gas and NGLs;
- economic conditions;
- supply disruptions;
- availability of supply connected to our systems; and
- availability and adequacy of infrastructure to gather and process supply into and out of our systems.

The volumes of natural gas, crude oil, condensate and NGLs gathered, processed, fractionated and transported on our assets also depend on the production from the regions that supply our systems. Supply of natural gas, crude oil, condensate and NGLs can be affected by many of the factors listed above, including commodity prices and

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

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

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

Construction of our major development projects subjects us to risks of construction delays, cost over-runs, limitations on our growth and negative effects on our

operating results, liquidity and financial position.

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

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

We typically do not obtain independent evaluations of hydrocarbon reserves connected to our gathering systems or that we otherwise service due to the unwillingness of producers to provide reserve information as well as the cost of such evaluations. Accordingly, we do not have independent estimates of total reserves serviced by our assets or the anticipated life of such reserves. If the total reserves or estimated life of the reserves is less than we anticipate and we are unable to secure additional sources, then the volumes transported on our gathering systems or

that we otherwise service in the future could be less than anticipated. A decline in the volumes could have a material adverse effect on our results of operations and financial condition.

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

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

We have made commitments to purchase natural gas in production areas based on production-area indices and to sell the natural gas into market areas based on market-area indices, pay the costs to transport the natural gas between the two points and capture the difference between the indices as margin. Changes in the index prices relative to each other (also referred to as basis spread) can significantly affect our margins or even result in losses. For example, we are a party to one contract with a term to 2019 to supply approximately 150,000 MMBtu/d of gas. We buy gas for this contract on several different production-area indices on our North Texas Pipeline and sell the gas into a different market area index. We realize a loss on the delivery of gas under this contract each month based on current prices. The pro forma balance sheet as of December 31, 2013 reflects a liability of $100.9 million related to this onerous performance obligation based on forecasted discounted cash obligations in excess of market under this gas delivery contract. Reduced supplies and narrower basis spreads in recent periods have increased the losses on this contract, and greater losses on this contract could occur in future periods if these conditions persist or become worse.

Our profitability is dependent upon prices and market demand for oil, condensate, natural gas and NGLs, which are beyond our control and have been volatile.

We are subject to significant risks due to fluctuations in commodity prices. We are directly exposed to these risks primarily in the gas processing component of our business. For the year ended December 31, 2013, approximately 3.5% of our total gross operating margin, on a pro forma basis giving effect to the business combination, was generated under percent of liquids contracts. Under these contracts we receive a fee in the form of a percentage of the liquids recovered and the producer bears all the cost of the natural gas shrink. Accordingly, our revenues under these contracts are directly impacted by the market price of NGLs.

We also realize processing gross operating margins under processing margin (margin) contracts. For the year ended December 31, 2013 approximately 2.2% of our total gross operating margin, on a pro forma basis giving effect to the business combination, was generated under processing margin contracts. We have a number of processing margin contracts for activities at our Plaquemine, Gibson and Pelican processing plants. Under this type of contract, we pay the producer for the full amount of inlet gas to the plant, and we make a margin based on the difference between the value of liquids recovered from the processed natural gas as compared to the value of the natural gas volumes lost (“shrink”) and the cost of fuel used in processing. The shrink and fuel losses are referred to as plant thermal reduction, or PTR. Our margins from these contracts can be greatly reduced or eliminated during periods of high natural gas prices relative to liquids prices. Although we do not currently have any processing margin contracts for our Blue Water and Eunice plants, we do have the opportunity to process liquids from wet gas flowing on the pipelines connected to these plants, as well as our other processing plants, when market pricing is favorable. Our Eunice and Blue Water plants are not profitable to operate unless market pricing is very favorable.

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

In the past, the prices of oil, condensate, natural gas and NGLs have been extremely volatile, and we expect this volatility to continue. For example, crude oil prices (based on the NYMEX futures daily close prices for the

prompt month) in 2013 ranged from a high of $110.53 per Bbl in September 2013 to a low of $86.68 per Bbl in April 2013. Weighted average NGL prices in 2013 (based on the Oil Price Information Service (OPIS) Napoleonville daily average spot liquids prices) ranged from a high of $1.09 per gallon in September 2013 to a low of $0.84 per gallon in June 2013. Natural gas prices (based on Gas Daily Henry Hub closing prices) during 2013 ranged from a high of $4.52 per MMBtu in December 2013 to a low of $3.08 per MMBtu in January 2013.

The markets and prices for oil, condensate, natural gas and NGLs depend upon factors beyond our control. These factors include the supply and demand for oil, condensate, natural gas and NGLs, which fluctuate with changes in market and economic conditions and other factors, including:

- the impact of weather on the demand for oil and natural gas;
- the level of domestic oil, condensate and natural gas production;

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

Changes in commodity prices may also indirectly impact our profitability by influencing drilling activity and well operations, and thus the volume of gas, crude oil and condensate we gather and process. The volatility in commodity prices may cause our gross operating margin and cash flows to vary widely from period to period. Our hedging strategies may not be sufficient to offset price volatility risk and, in any event, do not cover all of our throughput volumes. Moreover, hedges are subject to inherent risks, which we describe in "Item 7A. Quantitative and Qualitative Disclosure about Market Risk" in our Annual Report on Form 10-K for the year ended December 31, 2013. Our use of derivative financial instruments does not eliminate our exposure to fluctuations in commodity prices and interest rates and has in the past and could in the future result in financial losses or reduce our income.

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

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

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

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

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

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

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

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

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

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

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

operations and financial condition.

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

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

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

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

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

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

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

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

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

With completion of the business combination, we significantly increased the size of our business and expanded our business into geographic regions in which the former Crosstex Energy, L.P. did not previously operate, including the Cana and Arkoma Woodford Shales in Oklahoma. In order to operate effectively in these new regions, we need to understand the local market and regulatory environment and identify and retain certain employees from Devon who are familiar with these markets. If we are not successful in retaining these employees or operating in these new geographic areas, we may not be able to compete effectively in the new markets or fully realize the expected benefits of the business combination.

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

Our credit agreement and the indentures governing our senior notes contain, and any future indebtedness we incur will likely contain, a number of restrictive covenants that impose significant operating and financial

restrictions, including restrictions on our ability to engage in acts that may be in our best long-term interest. One or more of these agreements include covenants that, among other things, restrict our ability to:

- incur or guarantee additional indebtedness or issue preferred stock;
- pay dividends on our equity securities or redeem, repurchase or retire our equity securities or subordinated indebtedness;
- make investments;
- pay dividends or other distributions by our subsidiaries;
- engage in transactions with our affiliates;
- sell assets, including equity securities of our subsidiaries;
- consolidate or merge;
- incur liens;
- prepay, redeem and repurchase subordinated debt;
- make certain acquisitions;

- transfer assets;
- enter into sale and lease back transactions; and
- change business activities we conduct.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

In particular, our ability to renew or replace our existing contracts with industrial end-users and utilities impacts our profitability. For the year ended December 31, 2013, approximately 51.0% of our sales of gas that was transported using our physical facilities were to industrial end-users and utilities, on a pro forma basis giving effect to the business combination. As a consequence of the increase in competition in the industry and volatility of natural gas prices, end-users and utilities may be reluctant to enter into long-term purchase contracts. Many end-users purchase natural gas from more than one natural gas company and have the ability to change providers at any time. Some of these end-users also have the ability to switch between gas and alternate fuels in response to relative price fluctuations in the market. Because there are numerous companies of greatly varying size and financial capacity that compete with us in the marketing of natural gas, we often compete in the end-user and utilities markets primarily on the basis of price.

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

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

Increased regulation of hydraulic fracturing could result in reductions or delays in natural gas production by our customers, which could adversely impact our revenues.

A portion of our suppliers' and customers' natural gas production is developed from unconventional sources, such as deep gas shales, that require hydraulic fracturing as part of the completion process. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into the formation to stimulate gas production. Hydraulic fracturing activities are generally regulated by state oil and gas commissions; however, the Environmental Protection Agency (the "EPA") has asserted federal regulatory authority over certain hydraulic fracturing activities involving diesel under the Safe Drinking Water Act and has released draft permitting guidance for hydraulic fracturing activities that use diesel in fracturing fluids in those states where the EPA is the permitting authority. In addition, legislation has been proposed, but not passed that would provide for federal regulation of hydraulic fracturing and require disclosure of the chemicals used in the hydraulic-fracturing process. State legislatures and agencies are also enacting legislation and promulgating rules to regulate hydraulic fracturing and require disclosure of hydraulic fracturing chemicals.

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. In addition, the EPA is conducting a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater and has initiated plans to promulgate regulations controlling wastewater disposal associated with hydraulic fracturing and shale gas development. In addition to the EPA, other federal agencies are analyzing, or have been requested to review, a variety of environmental issues associated with hydraulic fracturing. These on-going or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the Safe Drinking Water Act, the Toxic Substances Control Act, or other statutory and/or

regulatory mechanisms. President Obama created the Interagency Working Group on Unconventional Natural Gas and Oil by Executive Order on April 13, 2012, which is charged with coordinating and aligning federal agency research and scientific studies on unconventional natural gas and oil resources.

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

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

The rates, terms and conditions of service under which we transport natural gas in our pipeline systems in interstate commerce are subject to regulation of the Federal Energy Regulatory Commission ("FERC") under Section 311 of the Natural Gas Policy Act and the rules and regulations promulgated under that statute. Under these regulations, we are required to justify our rates for interstate transportation service on a cost-of-service basis every five years. Our intrastate natural gas pipeline operations are subject to regulation by various agencies of the states in which they are located. Should FERC or any of these state agencies determine that our rates for Section 311 transportation service or intrastate transportation service should be lowered, our business could be adversely affected.

Our natural gas gathering and processing activities generally are exempt from FERC regulation under the Natural Gas Act. However, the distinction between FERC-regulated transmission services and federally unregulated gathering services is the subject of substantial, on-going litigation, so the classification and regulation of our gathering facilities are subject to change based on future determinations by FERC and the courts. Natural gas gathering may receive greater regulatory scrutiny at both the state and federal levels since FERC has less extensively regulated the gathering activities of interstate pipeline transmission companies and a number of such companies have transferred gathering facilities to unregulated affiliates. Our gathering operations also may be or become subject to safety and operational regulations relating to the design, installation, testing, construction, operation, replacement and management of gathering facilities. Additional rules and legislation pertaining to these matters are considered or adopted from time to time. We cannot predict what effect, if any, such changes might have on our operations, but the industry could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes.

Other state and local regulations also affect our business. We are subject to some ratable take and common purchaser statutes in the states where we operate. Ratable take statutes generally require gatherers to take, without undue discrimination, natural gas production that may be tendered to the gatherer for handling. Similarly, common purchaser statutes generally require gatherers to purchase without undue discrimination as to source of supply or producer. These statutes have the effect of restricting our right as an owner of gathering facilities to decide with whom we contract to purchase or transport natural gas. Federal law leaves any economic regulation of natural gas gathering to the states, and some of the states in which we operate have adopted complaint-based or other limited economic regulation of natural gas gathering activities.

States in which we operate that have adopted some form of complaint-based regulation, like Texas, generally allow natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to natural gas gathering access and rate discrimination.

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

Our liquids transportation pipelines in the Ohio River Valley and the Cajun-Sibon NGL pipeline, which went into service in November 2013, are subject to regulation by FERC under the ICA, the Energy Policy Act of 1992 and the rules and regulations promulgated under those laws. The ICA and its implementing regulations require that tariff rates and terms and conditions of service for interstate service on liquids pipelines be just, reasonable and not unduly discriminatory or preferential. The ICA also requires that such rates and terms and conditions be set forth in

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

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

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

The states in which we conduct operations administer federal pipeline safety standards under the Natural Gas Pipeline Safety Act of 1968. These standards only apply to certain natural gas gathering lines based on the gathering line's operating pressure and proximity to people. Because of their pressure and location, substantial portions of our gathering facilities are not regulated under that statute. The gathering line exemptions, however, may be revised in the future and place more of our gathering facilities under jurisdiction of the DOT. Nonetheless, our natural gas transmission pipelines are subject to regulation by the DOT. In response to pipeline accidents in other parts of the country, Congress and the DOT, through PHMSA, have passed or are considering heightened pipeline safety requirements that may be applicable to gathering lines. As a result, our pipeline facilities are subject to the Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011, which reauthorized funding for federal safety programs through 2015, increased penalties for safety violations, established additional safety requirements for newly constructed pipelines and required studies of certain safety issues that could result in the adoption of new regulatory requirements for existing pipelines.

At the state level, several states have passed legislation or promulgated rulemaking addressing pipeline safety. Compliance with pipeline integrity and other pipeline safety regulations issued by DOT or those issued by the Texas Railroad Commission, or TRRC, could result in substantial expenditures for testing, repairs and replacement. TRRC regulations require periodic testing of all intrastate pipelines meeting certain size and location requirements. Our costs relating to compliance with the required testing under the TRRC regulations were approximately at $7.0 million, $8.6 million, and $7.9 million for the years ended December 31, 2013, 2012 and 2011, respectively. We expect the costs for compliance with TRRC and DOT regulations to be approximately $5.0 million during 2014. If our pipelines fail to meet the safety standards mandated by the TRRC or the DOT regulations, then we may be required to repair or replace sections of such pipelines or operate the pipelines at a reduced maximum allowable operating pressure, the cost of which cannot be estimated at this time.

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

Due to the possibility of new or amended laws and regulations or reinterpretation of existing laws and regulations, there can be no assurance that future compliance with the PHMSA or state requirements will not have a material adverse effect on our results of operations or financial positions. As our operations continue to expand into and around urban or more populated areas, such as the Barnett Shale, we may incur additional expenses to mitigate

noise, odor and light that may be emitted in our operations and expenses related to the appearance of our facilities. Municipal and other local or state regulations are imposing various obligations including, among other things, regulating the location of our facilities, imposing limitations on the noise levels of our facilities and requiring certain other improvements that increase the cost of our facilities. We are also subject to claims by neighboring landowners for nuisance related to the construction and operation of our facilities, which could subject us to damages for declines in neighboring property values due to our construction and operation of facilities.

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

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

There is inherent risk of the incurrence of significant environmental costs and liabilities in our business due to our handling of natural gas, crude oil and other petroleum substances, our brine disposal operations, air emissions related to our operations, historical industry operations, waste disposal practices and the prior use of natural gas flow meters containing mercury. For example, we operate brine disposal wells in Ohio and West Virginia and may gather brine from surrounding states. These wells are regulated under the federal Safe Drinking Water Act (SDWA) as Class II wells and under state laws. State laws and regulations that govern these operations can be more stringent than the federal SDWA, such as the Ohio Department of Natural Resources rules which took effect October 1, 2012. These rules imposed new, more stringent environmentally responsible standards for the permitting and operating of brine disposal wells, including extensive review of geologic data and use of state of the art technology. They apply to new disposal wells and, as applicable, to existing wells. The Ohio Department of Natural Resources also imposes requirements on the transportation and disposal of brine. In addition, the possibility exists that stricter laws, regulations or enforcement policies could significantly increase our compliance costs and the cost of any remediation that may become necessary. We may incur material environmental costs and liabilities. Furthermore, our insurance may not provide sufficient coverage in the event an environmental claim is made against us.

In addition, state and federal regulatory agencies recently have focused on a possible connection between the operation of injection wells used for oil and gas waste waters and an observed increase in minor seismic activity and tremors. When caused by human activity, such events are called induced seismicity. Regulatory agencies are continuing to study possible linkage between injection activity and induced seismicity. To the extent these studies result in additional regulation of injection wells, such regulations could impose additional regulations, costs and restrictions on our brine disposal operations.

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

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

On April 17, 2012, the EPA issued final rules under the Clean Air Act that became effective on October 15, 2012. Among other things, these rules require additional emissions controls for natural gas and NGLs production, including New Source Performance Standards to address emissions of sulfur dioxide and volatile organic compounds (“VOCs”) and a separate set of emission standards to address hazardous air pollutants frequently associated with such production activities. The final regulations require, among other things, the reduction of VOC emissions from natural gas wells through the use of reduced emission completions or “green completions” on all hydraulically fractured wells constructed or refractured after January 1, 2015. Moreover, these rules establish specific requirements regarding emissions from compressors and controllers at natural gas gathering and boosting stations and processing plants together with dehydrators and storage tanks at natural gas processing plants, compressor stations and gathering and boosting stations. The rules also establish new requirements for leak detection and repair of leaks at natural gas processing plants that exceed 500 parts per million in concentration. These regulations could require a number of modifications to our operations and our natural gas exploration and production suppliers’ and customers’ operations, including the installation of new equipment, which could result in significant costs, including increased capital expenditures and operating costs. The incurrence of such expenditures and costs by our suppliers and customers could result in reduced production by those suppliers and customers and thus translate into reduced demand for our services. The rules are subject to an ongoing legal challenge brought by various parties, including environmental groups and industry, and the EPA has indicated that it may revise the rules. Any such revisions could affect our operations, as well as the operations of our suppliers and customers.

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

On December 15, 2009, the EPA published its findings that emissions of carbon dioxide, methane and other greenhouse gases (“GHGs”) present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth’s atmosphere and other climatic changes. These findings allowed the EPA to proceed with the adoption and implementation of regulations restricting emissions of GHGs under existing provisions of the federal Clean Air Act. Since 2011, the EPA has required stationary sources that emit GHGs above regulatory and statutory thresholds to obtain a Prevention of Significant Deterioration permit. Moreover, on October 30, 2009, the EPA published a “Mandatory Reporting of Greenhouse Gases” final rule that established a comprehensive scheme requiring operators of stationary sources emitting more than established annual thresholds of GHGs to inventory and report their GHG emissions annually on a facility-by-facility basis. The Mandatory Reporting Rule was expanded by a rule promulgated on November 30, 2010 to include owners and operators of onshore oil and natural gas production, processing, transmission, storage and distribution facilities. Reporting emissions from such onshore activities is required on an annual basis. The first reports were due in 2012 for emissions occurring in 2011. Additionally, the EPA has proposed to regulate greenhouse gas emissions from certain electric generating units under the Clean Air Act’s New Source Performance Standards (“NSPS”) program. The EPA may propose to regulate additional source categories under the NSPS program in the future.

In addition, the U.S. Congress has from time to time considered legislation to reduce emissions of GHGs, and almost half of the states have already taken legal measures to reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. Most of these cap and trade programs work by requiring either major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and NGL fractionation plants, to acquire and surrender emission allowances with the number of allowances available for purchase reduced each year until the overall GHG emission reduction goal is achieved. The adoption of legislation or regulations imposing reporting or permitting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur additional costs to reduce emissions of GHGs associated with our operations, could adversely affect our performance of operations in the absence of any permits that may be required to regulate emission of GHGs or could adversely affect demand for the natural gas we gather, process or otherwise handle in connection with our services.

Our business involves many hazards and operational risks, some of which may not be fully covered by insurance.

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

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

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

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

Comprehensive financial reform legislation was signed into law by the President on July 21, 2010. The legislation calls for the Commodities Futures Trading Commission ("CFTC") to regulate certain markets for derivative products, including over-the-counter ("OTC") derivatives. The CFTC has issued several new relevant regulations and other rulemakings are pending at the CFTC, the product of which would be rules that implement the mandates in the new legislation to cause significant portions of derivatives markets to clear through clearinghouses. The legislation and new regulations may also require counterparties to our derivative instruments to spin off some of their derivatives activities to separate entities, which may not be as creditworthy as the current counterparties. The new legislation and any new regulations could significantly increase the cost of derivative contracts, materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures and to generate sufficient cash flow to pay quarterly distributions at current levels or at all. Our revenues could be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material, adverse effect on us, our financial condition and our results of operations.

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

Our operations expose us to fluctuations in commodity prices, and our credit facility exposes us to fluctuations in interest rates. We use over-the-counter price and basis swaps with other natural gas merchants and financial institutions. Use of these instruments is intended to reduce our exposure to short-term volatility in commodity prices. As of December 31, 2013, we have hedged only portions of our expected exposures to commodity price risk. In addition, to the extent we hedge our commodity price risk using swap instruments, we will forego the benefits of favorable changes in commodity prices. Although we do not currently have any financial instruments to eliminate our exposure to interest rate fluctuations, we may use financial instruments in the future to offset our exposure to interest rate fluctuations.

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

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

Our financial statements may reflect gains or losses arising from exposure to commodity prices for which we are unable to enter into fully effective hedges. In addition, the standards for cash flow hedge accounting are rigorous. Even when we engage in hedging transactions that are effective economically, these transactions may not be considered effective cash flow hedges for accounting purposes. Our earnings could be subject to increased volatility to the extent our derivatives do not continue to qualify as cash flow hedges and, if we assume derivatives as part of an acquisition, to the extent we cannot obtain or choose not to seek cash flow hedge accounting for the derivatives we assume.

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

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

Risk Inherent in an Investment in the Partnership

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

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

We may not have sufficient available cash from operating surplus each quarter to enable us to make cash distributions at our current distribution rate under our cash distribution policy. The amount of cash we can distribute on our units principally depends upon the amount of cash we generate from our operations, which will fluctuate from quarter to quarter based on, among other things:

- the fees we charge and the margins we realize for our services;

- the prices of, levels of production of and demand for oil, natural gas, condensate and NGLs;
- the volume of natural gas we gather, compress, process, transport and sell, the volume of NGLs we process or fractionate and sell, the volume of crude oil we handle at our crude terminals, the volume of crude oil we gather, transport, purchase and sell and the volumes of brine we dispose;

- the relationship between natural gas and NGL prices;
- cash settlements of hedging positions;
- the level of competition from other midstream energy companies;
- the level of our operating and maintenance and general and administrative costs; and
- prevailing economic conditions.

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

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

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

Devon, through its control of ENLC, controls our general partner and indirectly has the power to appoint all of the officers and directors of our general partner. Although our general partner has a fiduciary duty to manage us in a manner that is beneficial to us and our unitholders, the directors and officers of our general partner have a fiduciary duty to manage our general partner in a manner that is beneficial to its owner, ENLC in which Devon owns the manager and a 70.4% limited liability company interest as of March 7, 2014. Conflicts of interest may arise in the future among Devon, ENLC and its affiliates, including our general partner, on the one hand, and our partnership and our unitholders, on the other hand. As a result of these conflicts our general partner may favor its own interests and those of its affiliates, including Devon and ENLC, over our interests. These conflicts include, among others, the following situations:

Conflicts Relating to Control

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

- our general partner controls the enforcement of obligations owed to us by our general partner and its affiliates;
- our general partner decides whether to retain separate counsel, accountants or others to perform services for us;
- in some instances our general partner may cause us to borrow funds from affiliates of the general partner or from third parties in order to permit the payment of cash distributions, even if the purpose or effect of the borrowing is to make incentive distributions; and
- our partnership agreement gives our general partner broad discretion in establishing financial reserves for the proper conduct of our business. These reserves also will affect the amount of cash available for distributions.

Conflicts Relating to Costs

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

Our unitholders have no right to elect our general partner or the directors of our general partner and have limited ability to remove our general partner.

Unlike the holders of common stock in a corporation, unitholders have only limited voting rights on matters affecting our business, and therefore limited ability to influence management's decisions regarding our business. Unitholders did not elect our general partner or the board of directors of our general partner and have no right to elect our general partner or the board of directors of our general partner on an annual or other continuing basis.

Furthermore, if unitholders are dissatisfied with the performance of our general partner, they will have little ability to remove our general partner. The general partner generally may not be removed except upon the vote of the holders of 66 2/3% of the outstanding units voting together as a single class. Affiliates of the general partner controlled approximately 59.9% of all the outstanding units as of March 7, 2014.

In addition, unitholders' voting rights are further restricted by the partnership agreement. It provides that any units held by a person that owns 20.0% or more of any class of units then outstanding, other than our general partner, its affiliates, their transferees and persons who acquired such units with the prior approval of the board of directors of the general partner, cannot be voted on any matter. In addition, the partnership agreement contains provisions limiting the ability of unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting the unitholders' ability to influence the manner or direction of management.

As a result of these provisions, it will be more difficult for a third party to acquire our partnership without first negotiating such a purchase with our general partner and, as a result, our unitholders are less likely to receive a takeover premium.

Cost reimbursements due to our general partner may be substantial and will reduce the cash available for distribution to our unitholders.

Prior to making any distributions on the units, we reimburse our general partner and its affiliates, including officers and directors of our general partner, for all expenses they incur on our behalf. The reimbursement of expenses could adversely affect our ability to make distributions to our unitholders. Our general partner has sole discretion to determine the amount of these expenses.

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

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

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

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

Our partnership agreement contains provisions that reduce the remedies available to our unitholders for actions that might otherwise constitute a breach of fiduciary duty by our general partner.

Our partnership agreement limits the liability and reduces the fiduciary duties of our general partner to our unitholders. The partnership agreement also restricts the remedies available to our unitholders for actions that would otherwise constitute breaches of our general partner's fiduciary duties. If you own a unit, you will be treated as having consented to the various actions contemplated in the partnership agreement and conflicts of interest that might otherwise be considered a breach of fiduciary duties under applicable state law.

We may issue additional units without our unitholders' approval, which would dilute our unitholders' ownership interests.

We may issue an unlimited number of limited partner interests of any type without the approval of our unitholders. The issuance of additional limited partner interests will have the following effects:

- our existing unitholders' proportionate ownership interest in us will decrease;
- the amount of cash available for distribution on each unit may decrease;
- the relative voting strength of each previously outstanding unit may be diminished; and
- the market price of the common units may decline.

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

If at any time our general partner and its affiliates own more than 80.0% of the common units, our general partner will have the right, but not the obligation, which it may assign to any of its affiliates or to us, to acquire all, but not less than all, of the common units held by unaffiliated persons at a price not less than their then-current market price. As a result, our unitholders may be required to sell their common units at an undesirable time or price and may therefore not receive any return on their investment. Existing unitholders may also incur a tax liability upon a sale of their units. As of March 7, 2014, ENLC and its affiliates owned 59.9% of our outstanding common units.

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

As of March 7, 2014, ENLC and its affiliates, including our largest holder Devon, held an aggregate of 138,552,244 units. The sale of any or all of these units in the public or private markets could have an adverse impact on the price of common units or on any trading market on which common units are held.

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

Our unitholders could be held liable for our obligations to the same extent as a general partner if a court determined that the right or the exercise of the right by our unitholders to remove or replace our general partner, to approve amendments to our partnership agreement, or to take other action under our partnership agreement constituted participation in the "control" of our business, to the extent that a person who has transacted business with the Partnership reasonably believes, based on our unitholders' conduct, that our unitholders are a general partner. Our general partner generally has unlimited liability for the obligations of the Partnership, such as its debts and environmental liabilities, except for those contractual obligations of the Partnership that are expressly made without recourse to our general partner. In addition, Section 17-607 of the Delaware Revised Uniform Limited Partnership Act provides that a limited partner who receives a distribution and knew at the time of the distribution that the distribution was in violation of that section may be liable to the limited partnership for the amount of the distribution for a period of three years from the date of the distribution. The limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in some of the other states in which we do business.

Tax Risks to Our Unitholders

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

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

If we were treated as a corporation for federal income tax purposes, we would pay additional tax on our income at corporate rates of up to 35.0% (under the law as of the date of this report) and we would probably pay state income taxes as well. In addition, distributions to unitholders would generally be taxed again as corporate distributions and none of our income, gains, losses or deductions would flow through to unitholders. Because a tax would be imposed upon us as a corporation, the cash available for distribution to unitholders would be substantially reduced. Therefore, treatment of us as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to the unitholders and thus would likely result in a material reduction in the value of the common units.

Current law may change so as to cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to entity-level taxation. At the federal level, members of Congress have considered substantive changes to the existing U.S. tax laws that would have affected certain publicly traded partnerships. Although the legislation considered would not have appeared to affect our tax treatment, we are unable to predict whether any such change or other proposals will ultimately be enacted. Moreover, any modification to the federal income tax laws and interpretations thereof may or may not be applied retroactively. At the state level, because of widespread state budget deficits, several states are evaluating ways to subject partnerships to entity level taxation through the imposition of state income, franchise and other forms of taxation. For example, we are required to pay Texas franchise tax at a maximum effective rate of 1.0% of our gross income apportioned to Texas in the prior year. If federal income tax or material amounts of additional state tax were to be imposed on us, the cash available for distribution to unitholders could be reduced and/or the value of an investment in our common units would be adversely impacted. Our partnership agreement provides that, if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for federal, state, or local income tax purposes, the minimum quarterly distribution amount and the target distribution amounts will be decreased to reflect the impact of that law on us.

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

We have not requested any ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes or any other matter affecting us. The IRS may adopt positions that differ from our counsel's conclusions expressed in this annual report or from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of our counsel's conclusions or the positions we take. A court may not agree with all of our counsel's conclusions or the positions we take. Any contest with the IRS may

materially and adversely impact the market for our common units and the prices at which our common units trade. In addition, our costs of any contest with the IRS will be borne by us and therefore indirectly by our unitholders and our general partner since such costs will reduce the amount of cash available for distribution by us.

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

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

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

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

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

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

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

Because we cannot match transferors and transferees of common units and because of other reasons, we will take depreciation and amortization positions that may not conform to all aspects of existing Treasury regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to unitholders. It also could affect the timing of these tax benefits or the amount of gain from the sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to the tax returns of unitholders.

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

We will be considered to have terminated our partnership for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a 12-month period. Our termination would, among other things, result in the closing of our taxable year for all unitholders, which would result in us filing two tax returns (and our unitholders could receive two Schedules K-1 if relief was not available, as described below) for one fiscal year if the termination occurs on a day other than December 31. Our termination could also result in a deferral of depreciation deductions allowable in computing our taxable income. In the case of a unitholder who has adopted a taxable year other than a fiscal year ending December 31, the closing of our taxable year may also result in more than twelve months of our taxable income or loss being includable in such unitholder's taxable income for the year of termination. Our termination would cause us to be treated as a new partnership for tax purposes for which we must make new tax elections, and we could be subject to penalties if we were to fail to recognize and properly report on our tax return that a termination occurred.

The IRS has recently announced a publicly traded partnership technical termination relief program whereby, if a publicly traded partnership that technically terminated its partnership makes a request for publicly traded partnership technical termination relief and such relief is granted by the IRS then, among other things, the partnership will only have to provide one Schedule K-1 to unitholders for the year notwithstanding two partnership tax years.

The tax treatment of publicly traded partnerships or an investment in our common units could be subject to potential legislative, judicial or administrative changes and differing interpretations, possibly on a retroactive basis.

The present federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units, may be modified by administrative, legislative or judicial interpretation at any time. Any modification to the federal income tax laws and interpretations thereof may or may not be applied retroactively. Moreover, any such modification could make it more difficult or impossible for us to meet the exception which allows publicly traded partnerships that generate qualifying income to be treated as partnerships (rather than corporations) for U.S. federal income tax purposes, affect or cause us to change our business activities, or affect the tax consequences of an investment in our common units. For example, members of Congress have been considering substantive changes to the definition of qualifying income and the treatment of certain types of income earned from profits interests in partnerships. While these specific proposals would not appear to affect our treatment as a partnership, we are unable to predict whether any of these changes, or other proposals, will ultimately be enacted. Any such changes could negatively impact the value of an investment in our common units.

We will adopt certain valuation methodologies and monthly conventions for federal income tax purposes that may result in a shift of income, gain, loss and deduction between our general partner and our unitholders. The IRS may challenge this treatment, which could adversely affect the value of the common units.

When we issue additional units or engage in certain other transactions, we will determine the fair market value of our assets and allocate any unrealized gain or loss attributable to our assets to the capital accounts of our unitholders and our general partner. Our methodology may be viewed as understating the value of our assets. In that case, there may be a shift of income, gain, loss and deduction between certain unitholders and our general partner, which may be unfavorable to such unitholders. Moreover, under our valuation methods, subsequent purchasers of common units may have a greater portion of their Internal Revenue Code Section 743(b) adjustment allocated to our tangible assets and a lesser portion allocated to our intangible assets. The IRS may challenge our valuation methods, or our allocation of the Section 743(b) adjustment attributable to our tangible and intangible assets, and allocations of taxable income, gain, loss and deduction between our general partner and certain of our unitholders.

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

Tax Treatment of Income Earned Through C Corporation Subsidiaries

A material portion of our taxable income is earned through C corporation subsidiaries. Such C corporation subsidiaries are subject to federal income tax on their taxable income at the corporate tax rate, which is currently a maximum of 35%, and will likely pay state (and possibly local) income tax at varying rates, on their taxable income. Any such entity level taxes will reduce the cash available for distribution to our unitholders. Distributions from any such C corporation subsidiary will generally be taxed again to unitholders as dividend income to the extent of current and accumulated earnings and profits of such subsidiary. As of January 1, 2014, the maximum federal income tax rate applicable to such dividend income which is allocable to individuals is 20%. An individual unitholder's share of dividend and interest income from our C corporation subsidiaries would constitute portfolio income that could not be offset by the unitholder's share of our other losses or deductions.

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

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

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

We prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The use of this proration method may not be permitted under existing Treasury Regulations, and, accordingly, our counsel is unable to opine as to the validity of this method. Recently, the U.S. Treasury Department issued proposed Treasury Regulations that provide a safe harbor pursuant to which publicly traded partnerships may use a similar monthly simplifying convention to allocate tax items among transferor and transferee unitholders. Nonetheless, the proposed regulations do not specifically authorize the use of the proration method we have adopted. If the IRS were to challenge this method or new Treasury regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

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

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

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

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

SELECTED COMBINED HISTORICAL FINANCIAL DATA OF ENLINK MIDSTREAM HOLDINGS, LP PREDECESSOR

The following table presents the selected historical financial and operating data of EnLink Midstream Holdings, LP Predecessor (the "Predecessor"), whose assets comprise the Midstream Business, for the periods indicated. The selected combined historical financial data of the Predecessor are derived from the historical combined financial statements of the Predecessor and should be read together with "Management's Discussion and Analysis of Financial Condition and Results of Operations" below and its audited combined financial statements for the year ended December 31, 2013 attached as Exhibit 99.4 to this Current Report on Form 8-K. The following information is only a summary and is not necessarily indicative of the results or future operations of the Predecessor.

	Year Ended December 31,				
	2013	2012	2011	2010	2009 (unaudited)
	(in millions, except per unit and operating data)				
Key Performance Measure					
Operating Margin (1)	$ 446.3	$ 365.3	$ 453.8	$ 427.6	$ 366.8
Operating Data					
Throughput (thousands of MMBtu/d)	2,708.4	2,720.6	2,637.4	2,470.0	2,294.2
NGL production (MBbls/d)	88.6	71.0	69.7	62.1	59.3
Statement of Income Data					
Operating revenues	$ 2,390.7	$ 2,000.8	$ 2,623.4	$ 2,016.0	$ 1,609.1
Operating expenses	(2,227.1)	(1,899.2)	(2,311.8)	(1,766.9)	(1,436.7)
Operating income	163.6	101.6	311.6	249.1	172.4
Income from equity investment	14.8	2.0	9.3	5.1	5.0
Income tax expense	(64.2)	(37.3)	(115.5)	(91.5)	(63.8)
Net income from continuing operations	114.2	66.3	205.4	162.7	113.6
Net income from discontinued operations	1.3	9.5	10.7	16.0	11.6
Net income	$ 115.5	$ 75.8	$ 216.1	$ 178.7	$ 125.2
Balance Sheet Data					
Net property, plant and equipment	$ 1,840.4	$ 1,843.2	$ 1,687.0	$ 1,574.6	$ 1,499.2
Total assets	$ 2,309.8	$ 2,535.2	$ 2,446.3	$ 2,336.0	$ 2,276.6
Total long-term liabilities	$ 481.4	$ 449.8	$ 461.0	$ 418.0	$ 318.1
Total equity	$ 1,783.7	$ 2,002.0	$ 1,901.3	$ 1,849.0	$ 1,869.7
Cash Flow Data					
Net cash flows provided by (used in):					
Operating activities	$ 360.5	$ 254.4	$ 401.2	$ 391.5	$ —
Investing activities	$ (242.9)	$ (368.5)	$ (268.6)	$ (220.4)	$ —
Financing activities	$ (117.6)	$ 114.1	$ (132.6)	$ (171.1)	$ —

(1) Operating margin is a non-GAAP financial measure. See below for additional information and a reconciliation of operating margin to operating income, which is its most directly comparable GAAP financial measure.

Predecessor Non-GAAP Financial Measure

The selected combined historical financial data of the Predecessor includes operating margin, a non-GAAP financial measure.

The Predecessor's operating margin is defined as operating revenues less product purchases and operations and maintenance expenses. The Predecessor uses operating margin as a performance measure of the core profitability of its operations. As an indicator of the Predecessor's operating performance, operating margin should not be considered an alternative to, or more meaningful than, operating income or net income as determined in accordance with GAAP. The Predecessor's operating margin may not be comparable to similarly titled measures of other companies because other entities may not calculate these amounts in the same manner.

The following table provides a reconciliation of the Predecessor's operating margin to operating income, which is the most directly comparable GAAP financial measure:

	Years Ended December 31,				
	2013	2012	2011	2010	2009
	(in millions)				
Predecessor's operating margin	$ 446.3	$ 365.3	$ 453.8	$ 427.6	$ 366.8
Add (deduct):					
Depreciation and amortization	(199.0)	(159.8)	(144.8)	(124.9)	(136.6)
General and administrative	(47.0)	(43.6)	(40.1)	(39.4)	(44.8)
Non-income taxes	(18.0)	(13.2)	(15.3)	(13.8)	(12.5)
Asset impairments	(18.2)	(50.1)	—	—	—
Other, net	(0.5)	3.0	58.0	(0.4)	(0.5)
Operating income	$ 163.6	$ 101.6	$ 311.6	$ 249.1	$ 172.4

Non-GAAP Financial Measure

Predecessor includes in this exhibit the non-GAAP financial measure ''Adjusted EBITDA.'' The Predecessor uses Adjusted EBITDA as a performance and liquidity measure to assess the ability of its assets to generate cash sufficient to pay interest costs and support indebtedness. The Partnership expects that Adjusted EBITDA will be a financial measure reported to its lenders and used as a gauge for compliance with some of its anticipated financial covenants under its credit facility. The Partnership defines Adjusted EBITDA as income from continuing operations before interest expense, income taxes, depreciation and amortization expense, impairments, stock-based compensation, income from equity investment, non-controlling interests and other income related items plus distributions from equity investment. The Partnership uses

Adjusted EBITDA to assess:

- the financial performance of its assets, without regard to financing methods, capital structure or historical cost basis;
- its operating performance and return on capital as compared to other companies in the midstream energy sector, without regard to financing or capital structure; and
- the viability of acquisitions and capital expenditure projects.

Adjusted EBITDA is a non-GAAP financial measure. The GAAP measure most directly comparable to Adjusted EBITDA is net income attributable to Midstream Holdings. The non-GAAP financial measure of Adjusted EBITDA should not be considered as an alternative to the GAAP measures of net income attributable to Midstream Holdings. Adjusted EBITDA is not a presentation made in accordance with GAAP and has important limitations as an analytical tool because it includes some, but not all, items that are included in net income are attributable to Midstream Holdings. You should not consider Adjusted EBITDA in isolation or as a substitute for analysis of results as reported under GAAP. Midstream Holdings and EnLink's definition of Adjusted EBITDA may not be comparable to similarly titled measures of other companies.

The following table presents a reconciliation of the Predecessor's net income to Adjusted EBITDA:

	Years Ended December 31,				
	2013	2012	2011	2010	2009
	(In millions)				
Net income from continuing operations attributable to Predecessor	$ 114.2	$ 66.3	$ 205.4	$ 162.7	$ 113.6
Depreciation and amortization	199.0	159.8	144.8	124.9	136.6
Impairment	18.2	50.1	—	—	—
Income from equity investment	(14.8)	(2.0)	(9.3)	(5.1)	(5.0)
Distributions from equity investment	12.0	2.3	8.3	8.7	5.0
Stock-based compensation	12.8	12.8	12.6	12.7	12.3
Taxes	64.2	37.3	115.5	91.5	63.8
Other (a)	0.5	(3.0)	(58.0)	0.4	0.5
Adjusted EBITDA	$ 406.1	$ 323.6	$ 419.3	$ 395.8	$ 326.8

(a) Other income is not included in adjusted EBITDA.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS OF ENLINK MIDSTREAM PARTNERS, LP

The historical financial statements included in this filing reflect the assets, liabilities and operations of the historical predecessor of EnLink Midstream Partners, LP (formerly known as Crosstex Energy, L.P.) (the "Partnership") following the Partnership's acquisition (the "Acquisition") of 50% of the outstanding limited partner interests in EnLink Midstream Holdings, LP (formerly known as Devon Midstream Holdings, L.P.) ("Midstream Holdings") and all of the outstanding equity interests in EnLink Midstream Holdings GP, LLC (formerly known as Devon Midstream Holdings GP, LLC), the general partner of Midstream Holdings ("Midstream Holdings GP" and, together with Midstream Holdings and their subsidiaries, the "Midstream Group Entities").

Under the acquisition method of accounting, Midstream Holdings is considered the historical predecessor of the Partnership's business because Devon Energy Corporation ("Devon") obtained control of the Partnership through its control of EnLink Midstream, LLC ("ENLC") and ENLC's indirect acquisition of EnLink Midstream GP, LLC (formerly known as Crosstex Energy GP, LLC) (the "General Partner") concurrently with the consummation of the Acquisition (collectively, the "business combination"). Accordingly, the following discussion analyzes the results of operations and financial condition of EnLink Midstream Holdings, LP Predecessor (the "Predecessor"), the predecessor to Midstream Holdings. The Predecessor is comprised of all of the U.S. midstream assets and operations of Devon prior to the business combination, including its 38.75% economic interest in Gulf Coast Fractionators. However, in connection with the business combination, only the Predecessor's systems serving the Barnett, Cana-Woodford and Arkoma-Woodford Shales in Texas and Oklahoma, as well as the economic burdens and benefits of the 38.75% economic interest in Gulf Coast Fractionators, was contributed to Midstream Holdings, effective as of December 31, 2013. These contributed assets represent 95.2% of the Predecessor's operating income for the year ended December 31, 2013.

The following discussion analyzes the results of operations and financial condition of the Predecessor, including the less significant assets that were not contributed to Midstream Holdings in connection with the business combination. You should read this discussion in conjunction with the historical and pro forma financial statements and accompanying notes included in this filing. All references in this section to Midstream Holdings, as well as the terms "our," "we," "us" and "its," refer to the Predecessor when used in historical context. All references in this section to the Partnership, as well as the terms "our," "we," "us" and "its," refer to the EnLink Midstream Partners, LP, together with its consolidated subsidiaries, when referring to current or future events.

This management's discussion and analysis of financial condition and results of operations contains forward-looking statements that involve risks, uncertainties and assumptions. See "Disclosure Regarding Forward-Looking Statements" for a discussion of the risks, uncertainties and assumptions associated with those statements. Our actual results may differ materially from those discussed in the forward-looking statements as a result of various factors, including but not limited to those in "Risk Factors" and included in other portions of this filing.

Overview

We are a Delaware limited partnership formed on July 12, 2002. We primarily focus on providing midstream energy services, including gathering, transmission, processing, fractionation and marketing, to producers of natural gas, NGLs, crude oil and condensate. We also provide crude oil, condensate and brine services to producers. Our midstream energy asset network includes approximately 7,300 miles of pipelines, 12 natural gas processing plants, six fractionators, 3.1 million barrels of NGL cavern storage, rail terminals, barge terminals, truck terminals and a fleet of approximately 100 trucks.

Effective as of March 7, 2014, our wholly-owned subsidiary acquired 50% of the outstanding limited partner interests in Midstream Holdings and all of the outstanding equity interests in Midstream Holdings GP in exchange for the issuance by the Partnership of 120,542,441 units representing a new class of limited partnership interests in the Partnership. At the same time, Crosstex Energy, Inc. (to be renamed EnLink Midstream, Inc.), the entity that directly owns our General Partner, became a wholly-owned subsidiary of ENLC. Another wholly-owned subsidiary of ENLC owns the remaining 50% of the outstanding limited partner interests in Midstream Holdings.

Midstream Holdings owns midstream assets consisting of natural gas gathering and transportation systems, natural gas processing facilities and NGL fractionation facilities located in Texas and Oklahoma. Midstream Holdings' primary assets consist of three processing facilities with 1.3 Bcf/d of natural gas processing capacity, approximately 3,685 miles of pipelines with aggregate capacity of 2.9 Bcf/d and fractionation facilities with up to 160 MBbls/d of aggregate NGL fractionation capacity. These assets include the following systems and facilities.

· ***Barnett assets*** —Midstream Holdings owns the following midstream assets in the Barnett Shale:

· *Bridgeport processing facility* —This natural gas processing facility is one of the largest processing plants in the U.S. with 790 MMcf/d of processing capacity, 63 MBbls/d of NGL production capacity and 15 MBbls/d of NGL fractionation capacity.

· *Bridgeport rich gathering system* —This rich natural gas gathering system consists of approximately 2,442 miles of low- and intermediate-pressure pipeline segments with approximately 145,000 horsepower of compression.

· *Bridgeport lean gathering system* —This lean natural gas gathering system consists of approximately 300 miles of low-, intermediate- and high-pressure pipeline segments with approximately 59,000 horsepower of compression.

· *Acacia transmission system* —This transmission system consists of approximately 120 miles of pipeline, associated storage and approximately 17,000 horsepower of compression and interconnects the tailgate of the Bridgeport processing facility and the Bridgeport lean gathering system to intrastate pipelines as well as two local power plants.

· *East Johnson County gathering system* —This natural gas gathering system consists of approximately 270 miles of low-, intermediate- and high-pressure pipeline segments with approximately 41,000 horsepower of compression.

· ***Cana system*** —This natural gas gathering and processing system is located in the Cana-Woodford Shale in West Central Oklahoma and consists of a 350 MMcf/d processing facility, 30 MBbls/d of NGL production capacity and approximately 413 miles of associated low-, intermediate- and high-pressure pipeline segments with approximately 92,500 horsepower of compression.

· ***Northridge system*** —This natural gas gathering and processing system is located in the Arkoma-Woodford Shale in Southeastern Oklahoma and consists of a 200 MMcf/d processing facility, 17 MBbls/d of NGL production capacity and approximately 140 miles of associated low-, intermediate- and high-pressure pipeline segments with approximately 18,000 horsepower of compression.

· ***Gulf Coast Fractionators*** —Midstream Holdings holds a contractual right to the economic burdens and benefits of a 38.75% interest in Gulf Coast Fractionators held by Devon. Gulf Coast Fractionators owns an NGL fractionator located on the Texas Gulf Coast at the Mont Belvieu hub. This facility has a capacity of approximately 145 MBbls/d.

Midstream Holdings' Operations

Midstream Holdings' results are driven primarily by the volumes of natural gas it gathers, processes and transports through its systems. This volume throughput is substantially dependent on Devon's success in the regions where Midstream Holdings operates. Devon is a leading independent energy company engaged primarily in the exploration, development and production of oil, natural gas and NGLs. Devon is the largest natural gas producer in the Barnett and Cana-Woodford Shales, the largest NGL producer in the Barnett Shale and one of the largest NGL producers in the Cana-Woodford Shale.

In Midstream Holdings' gathering operations, it contracts with producers to gather natural gas from individual wells located near its gathering systems. Midstream Holdings connects wells to gathering lines through which natural gas is compressed and may be delivered to a processing plant or downstream pipeline, and ultimately to end-users.

The Predecessor historically provided services to Devon pursuant to fixed-fee and percent-of-proceeds contracts and historically took title to the natural gas it gathered and processed. The Predecessor's percent-of-proceeds arrangements were based on the sales value of extracted NGLs and residue natural gas that resulted from natural gas processing.

In connection with the consummation of the Merger, Midstream Holdings has entered into new contracts with Devon pursuant to which it provides services under fixed-fee arrangements based on the volume and thermal content of the natural gas gathered, processed and transported and does not take title to the natural gas gathered, processed and transported. Under these arrangements, Midstream Holdings provides gathering and processing services to Devon, and Devon has dedicated to Midstream Holdings natural gas production for 10 years from 795,000 net acres in the Barnett, Cana-Woodford and Arkoma-Woodford Shales. Midstream Holdings expects all of these dedications to result in associated deliveries to its Bridgeport, Cana, East Johnson County and Northridge systems. Devon has provided five-year minimum natural gas volume commitments to Midstream Holdings of 850 MMcf/d to the Bridgeport gathering systems, 650 MMcf/d to the Bridgeport processing facility, 125 MMcf/d to the East Johnson County gathering system, 330 MMcf/d to the Cana system and 40 MMcf/d to the Northridge system.

Midstream Holdings believes these contracts provide it with a relatively steady revenue stream that is not subject to direct commodity price risk during the term of the five-year minimum volume commitments. After the five-year minimum volume commitments, Midstream Holdings will nevertheless continue to have indirect exposure to commodity price risk in that persistently low commodity prices may cause Devon to delay drilling or shut in production, which would reduce the throughput on Midstream Holdings' assets.

How Midstream Holdings Evaluates its Operations

Midstream Holdings uses a variety of financial and operational metrics to evaluate its performance. These metrics help Midstream Holdings identify factors and trends that impact Midstream Holdings' operating results, profitability and financial condition. The key metrics Midstream Holdings uses to evaluate its business are provided below.

Operating Margin

Midstream Holdings uses operating margin as a performance measure of the core profitability of its operations. Midstream Holdings defines operating margin as total operating revenues, which consist of revenues generated from the sale of natural gas and NGLs plus service fee revenues, less the cost of product purchases, consisting primarily of producer payments and other natural gas purchases, and operations and maintenance expenses. Midstream Holdings uses operating margin to assess:

· the financial performance of Midstream Holdings' assets, without regard to financing methods, capital structure or historical cost basis;

· Midstream Holdings' operating performance and return on capital as compared to other companies in the midstream energy sector, without regard to financing or capital structure; and

· the viability of acquisitions and capital expenditure projects.

Natural Gas Throughput

Midstream Holdings must continually obtain additional supplies of natural gas to maintain or increase throughput on its systems. Midstream Holdings' ability to maintain existing supplies of natural gas and obtain additional supplies is primarily impacted by its acreage dedication and the level of successful drilling activity by Devon and, to a lesser extent, the acreage dedications with and successful drilling by other producers.

Items Affecting Comparability of Midstream Holdings' Financial Results

The historical financial results of the Predecessor discussed below may not be comparable to Midstream Holdings' future financial results for the following reasons:

- The Predecessor's historical assets comprised all of Devon's U.S. midstream assets and operations. However, only its assets serving the Barnett, Cana-Woodford and Arkoma-Woodford Shales, as well as the 38.75% economic interest in Gulf Coast Fractionators, were contributed to Midstream Holdings in connection with the consummation of the Merger. These assets generated approximately 96% of the Predecessor's net income from continuing operations for year ended December 31, 2013.

- Midstream Holdings has entered into new agreements with Devon pursuant to which Midstream Holdings provides services under fixed-fee arrangements and no longer takes title to the natural gas gathered and processed or the NGLs it fractionates.

- The Predecessor's historical combined financial statements include U.S. federal and state income tax expense. Due to Midstream Holdings' status as a partnership, the 50% interest in Midstream Holdings that is owned directly by the Partnership will not be subject to U.S. federal income tax and certain state income taxes in the future.

- All historical affiliated transactions related to Midstream Holdings' continuing operations were net settled within its combined financial statements because these transactions related to Devon and were funded by Devon's working capital. In the future, all of Midstream Holdings' transactions will be funded by its working capital. This will impact the comparability of its cash flow statements, working capital analysis and liquidity discussion.

General Trends and Outlook

Natural Gas and NGL Supply and Demand

Midstream Holdings' gathering and processing operations are generally dependent upon natural gas production from Devon's upstream activity in its areas of operation. The significant decline in natural gas prices as a result of significant new supplies of domestic natural gas production has caused a related decrease in dry natural gas drilling by many producers in the United States. Depressed oil and natural gas prices could affect production rates over time and levels of investment by Devon and third parties in exploration for and development of new oil and natural gas reserves. In addition, there is a natural decline in production from existing wells that are connected to Midstream Holdings' gathering systems. Midstream Holdings believes Devon's five-year minimum volume commitments substantially reduce Midstream Holdings' volumetric risk over that period of time. After the expiration of these five-year minimum volume commitments, a material decline in the volume of natural gas that Midstream Holdings gathers and transports on its systems would result in a material decline in its total operating revenues and cash flows. Although Midstream Holdings expects that Devon will continue to devote substantial resources to the development of the Barnett and Cana-Woodford Shales, it has no control over this activity and Devon has the ability to reduce or curtail such development at its discretion.

Rising Operating Costs and Inflation

The current level of exploration, development and production activities across the United States has resulted in increased competition for personnel and equipment. This competition has caused, and Midstream Holdings believes it will continue to cause, increases in the prices it pays for labor, supplies and property, plant and equipment. An increase in the general level of prices in the economy could have a similar effect on the operating costs Midstream Holdings incurs. Midstream Holdings will attempt to recover increased costs from its customers, but there may be a delay in doing so or it may be unable to recover all these costs. To the extent Midstream Holdings is unable to procure necessary supplies or recover higher costs, its operating results will be negatively impacted.

Regulatory Compliance

The regulation of natural gas gathering and transportation activities by FERC and other federal and state regulatory agencies, including the DOT, has a significant impact on Midstream Holdings' business. For example, PHMSA has established pipeline integrity management programs that require more frequent inspections of pipeline facilities and other preventative measures, which may increase Midstream Holdings' compliance costs and increase the time it takes to obtain required permits. Additionally, increased regulation of oil and natural gas producers, including regulation associated with hydraulic fracturing, could reduce regional supply of oil and natural gas and therefore throughput on Midstream Holdings' gathering systems.

Results of Predecessor's Operations

The following schedule presents the Predecessor's historical combined key operating and financial metrics.

	Year Ended December 31,		
	2013	2012	2011
	($ in millions, except prices)		
Operating revenues	$ 2,390.7	$ 2,000.8	$ 2,623.4
Product purchases	(1,773.7)	(1,464.5)	(2,014.1)
Operations and maintenance expenses	(170.7)	(171.0)	(155.5)
Operating margin	446.3	365.3	453.8
Other operating expenses, net	(282.7)	(263.7)	(142.2)
Income from equity investment	14.8	2.0	9.3
Income tax expense	(64.2)	(37.3)	(115.5)
Net income from continuing operations	114.2	66.3	205.4
Net income from discontinued operations	1.3	9.5	10.7
Net income attributable to Devon	$ 115.5	$ 75.8	$ 216.1
Throughput (thousands of MMBtu/d):			
Bridgeport rich gathering system	861.1	818.4	811.6

Bridgeport lean gathering system	261.8	298.0	296.0
Acacia transmission system	741.8	732.7	700.1
East Johnson County gathering system	236.8	277.8	258.0
Barnett assets	2,101.5	2,126.9	2,065.7
Cana gathering system	320.7	265.7	175.7
Northridge gathering system	69.2	85.0	109.5
Other systems	217.0	243.0	286.5
Total	2,708.4	2,720.6	2,637.4
NGL production (MBbls/d):			
Bridgeport processing facility	58.9	49.4	52.8
Cana processing facility	18.8	12.1	3.9
Northridge processing facility	8.2	6.8	10.5
Other systems	2.7	2.7	2.5
Total	88.6	71.0	69.7
Residue natural gas production (thousands of MMBtu/d):			
Bridgeport processing facility	623.1	613.1	599.5
Cana processing facility	242.1	209.7	151.5
Northridge processing facility	52.2	65.5	85.3
Other systems	7.4	7.4	2.6
Total	924.8	895.7	838.9
Realized prices:			
NGLs ($/Bbl)	$ 30.05	$ 35.38	$ 49.16
Residue natural gas ($/MMBtu)	$ 3.18	$ 2.38	$ 3.58

Since 2011, operating margin has consistently improved as a result of production growth. The largest contributors to rising production have been Midstream Holdings' Cana, Bridgeport rich, and Acacia systems, with daily throughput growth of 83%, 6%, and 6%, respectively, from 2011 to 2013. This growth is the result of Devon and other producers developing liquids-rich natural gas production in the Cana-Woodford and Barnett Shales. However, overall growth has been limited by throughput declines for the Predecessor's other systems, which are the result of natural gas price decreases. As natural gas prices have dropped relative to oil and NGL prices in recent years, many producers, including Devon, have focused on growing their oil and liquids-rich natural gas production rather than dry natural gas. Consequently, Midstream Holdings' systems serving liquids-rich natural gas regions in the Cana-Woodford and Barnett Shales have higher throughput, while Midstream Holdings' systems serving dry natural gas regions have experienced throughput declines.

Prices have also impacted operating margin. Since 2011, NGL prices have declined significantly, which has negatively impacted operating margin. Natural gas prices have been volatile, increasing in 2013 after a significant decline in 2012.

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012

Operating Margin

Operating margin increased $81.0 million, or 22%, from the year ended December 31, 2012 to the year ended December 31, 2013, as summarized in the following schedule:

	(in millions)
Operating margin, 2012	$ 365.3
Change due to volumes	32.3
Change due to pricing	48.4
Change due to operations and maintenance expenses	0.3
Operating margin, 2013	$ 446.3

Higher gathering, processing and transportation volumes were responsible for an increase in operating margin of $32.3 million for the year ended December 31, 2013 compared to the year ended December 31, 2012. Higher volumes were primarily the result of NGL production increasing 25%, resulting in $34.1 million of higher operating margin. The increase in NGL production was largely driven by higher inlet volumes at the Cana processing facility, improved efficiencies at the Cana and Bridgeport processing facilities and unplanned downtime impacting Midstream Holdings' Bridgeport processing facility in 2012. The increase in NGL production was partially offset by slightly lower throughput volumes, primarily on the Predecessor's East Johnson and Northridge gathering systems.

Changes in pricing led to an increase in operating margin of $48.4 million for the year ended December 31, 2013 compared to the year ended December 31, 2012. Natural gas pipeline fees increased 15 %, which resulted in $44.2 million of additional revenues. Additionally, higher residue natural gas prices contributed an additional $32.4 million to operating margin. These increases were partially offset by lower margins of $28.2 million primarily due to NGL price declines.

Operations and maintenance expenses decreased $0.3 million, or 0%.

Other Operating Expenses, Net

Other operating expenses, net increased $19.0 million, or 7%, from the year ended December 31, 2012 to the year ended December 31, 2013, as summarized in the following schedule:

	2013	2012	Change
		(in millions)	
Depreciation and amortization	$ 199.0	$ 159.8	$ 39.2
General and administrative	47.0	43.6	3.4
Non-income taxes	18.0	13.2	4.8
Asset impairments	18.2	50.1	(31.9)
Other, net	0.5	(3.0)	3.5
Other operating expenses, net	$ 282.7	$ 263.7	$ 19.0

Depreciation and amortization expense increased $39.2 million, or 25%, from 2012 to 2013. The increase primarily resulted from higher capitalized costs on the Cana system. Devon and other producers have continued to grow natural gas production in the Cana-Woodford Shale. As a result, we have increased our throughput capacity by expanding our pipeline and gathering systems and our Cana processing facility.

Historical general and administrative expenses consist of costs allocated by Devon for shared services that consist primarily of accounting, treasury, information technology, human resources, legal and facilities management. The costs were

allocated based on a proportionate share of Devon's revenues, employee compensation and gross property, plant and equipment.

General and administrative expense increased $3.4 million, or 8%, primarily due to higher employee compensation and benefits.

Non-income tax expense consists primarily of ad valorem taxes. Non-income taxes increased $4.8 million, or 36%, from 2012 to 2013 primarily due to higher ad valorem tax assessments on Midstream Holdings' Cana assets.

In 2013 and 2012, Devon recognized asset impairments of $18.2 million and $50.1 million, respectively. Devon determined that the carrying amounts of certain midstream facilities located in south and east Texas were not recoverable from estimated future cash flows due to declining dry natural gas production. Consequently, the assets were written down to their estimated fair values, which were determined using discounted cash flows. None of the asset impairments in 2013 were related to assets that were contributed to Midstream Holdings.

During 2013 and 2012, our Predecessor recognized $0.5 million of net other expense and $3.0 million of net other income, respectively. In the second quarter of 2012, Predecessor received insurance proceeds of $5.6 million related to business interruption that occurred at Gulf Coast Fractionators.

Income Tax Expense. During 2013 and 2012, effective income tax rates were 36% for both periods. These rates differed from the U.S. statutory income tax rate due to the effect of state income taxes.

Discontinued Operations. The Predecessor has sold certain non-core assets that are presented as discontinued operations in the Predecessor's historical financial statements. Net income from discontinued operations decreased $8.2 million from 2012 to 2013. The decrease was primarily due to the gain recognized on the divestiture of the West Johnson County processing facility and gathering system in 2012.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011

Operating Margin. Operating margin decreased $88.5 million, or 20%, from the year ended December 31, 2011 to the year ended December 31, 2012, as summarized in the following schedule:

		(in millions)
Operating margin, 2011	$	453.8
Change due to volumes		20.8
Change due to pricing		(93.8)
Change due to operations and maintenance expenses		(15.5)
Operating margin, 2012	$	365.3

Higher gathering, processing and transportation volumes were responsible for an increase in operating margin of $20.8 million for the year ended December 31, 2012 compared to the year ended December 31, 2011. Residue volumes increased 7%, resulting in a $9.1 million increase to operating margin. The remainder of the operating margin increase resulted from higher natural gas gathered volumes and NGL production, which increased 3% and 2%, respectively. These volume increases primarily resulted from the restart of Midstream Holdings' Cana processing facility following tornado damage in 2011, higher volumes on Midstream Holdings' East Johnson County gathering system and continued development of the liquids-rich areas in the Cana-Woodford and Barnett Shales.

Changes in pricing led to a decrease in operating margin of $93.8 million for the year ended December 31, 2012 compared to the year ended December 31, 2011. Lower NGL and residue natural gas prices reduced operating margin by $71.0 million and $42.8 million, respectively. These decreases were partially offset by higher gathering and compression fees which increased $20.0 million, or 9%.

Operations and maintenance expenses increased $15.5 million, or 10%, partially due to higher volumes, including the Cana system expansion. Expenses also increased due to repair and testing activities that were required on Midstream Holdings' Bridgeport gathering systems in 2012.

Other Operating Expenses, Net. Other operating expenses, net increased $121.5 million, or 85%, from the year ended December 31, 2011 to the year ended December 31, 2012, as summarized in the following schedule:

		2012		2011 (in millions)		Change
Depreciation and amortization	$	159.8	$	144.8	$	15.0
General and administrative		43.6		40.1		3.5
Non-income taxes		13.2		15.3		(2.1)
Asset impairments		50.1		—		50.1
Other, net		(3.0)		(58.0)		55.0
Other operating expenses, net	$	263.7	$	142.2	$	121.5

Depreciation and amortization expense increased $15.0 million, or 10%, from 2011 to 2012. The increase primarily resulted from higher capitalized costs on the Cana system. Devon and other producers have continued to grow natural gas production in the Cana-Woodford Shale. As a result, Midstream Holdings increased throughput capacity by expanding its pipeline and gathering systems and our Cana processing facility.

Historical general and administrative expenses consist of costs allocated by Devon for shared services that consist primarily of accounting, treasury, information technology, human resources, legal and facilities management. The costs were allocated based on a proportionate share of Devon's revenues, employee compensation and gross property, plant and equipment.

General and administrative expense increased $3.5 million, or 9%, from 2011 to 2012, primarily due to higher employee compensation and benefits.

Non-income tax expense consists primarily of ad valorem taxes. Non-income taxes decreased $2.1 million, or 14%, from 2011 to 2012 primarily due to lower ad valorem tax assessments on Midstream Holdings' Barnett assets.

The following schedule summarizes asset impairments recognized in 2012. There were no asset impairments in 2011. Due to declining natural gas production resulting from low natural gas and NGL prices, Midstream Holdings' determined that the carrying amounts of certain of the Predecessors' midstream assets, including the Northridge system, were not recoverable from estimated future cash flows. Consequently, the Northridge system and other assets of the Predecessor were written down to their estimated fair values, which were determined using discounted cash flow models.

		2012
		(in millions)
Northridge	$	16.4
Other assets not being contributed to Midstream Holdings		33.7
Total asset impairments	$	50.1

During 2012 and 2011, the Predecessor recognized $3.0 million and $58.0 million of net other income, respectively. In 2012, the Predecessor received insurance proceeds of $5.6 million related to business interruption that occurred at Gulf Coast Fractionators. In 2011, the Predecessor received $57.8 million of excess insurance recoveries related to business interruption and equipment damage at the Cana system that resulted from tornadoes.

Income Tax Expense. During 2012 and 2011, Midstream Holdings' effective income tax rates were 36% for both periods. These rates differed from the U.S. statutory income tax rate due to the effect of state income taxes.

Discontinued Operations. Net income from discontinued operations decreased $1.2 million from 2011 to 2012. The decrease was due to lower operating earnings subsequent to the divestiture of the West Johnson County processing facility and gathering system in 2012, partially offset by the $8.3 million gain recognized on the divestiture.

Liquidity and Capital Resources

Midstream Holdings' Sources and Uses of Cash

The following schedule presents Midstream Holdings' sources and uses of cash:

	Year Ended December 31,					
		2013		2012		2011
Continuing operations:						
Operating cash flow	$	360.5	$	254.4	$	401.2
Capital expenditures		(243.1)		(351.7)		(247.6)
Contributions from (distributions to) owners		(117.6)		115.7		(131.1)
Other, net		0.2		(18.4)		(22.5)
Net change in cash		—		—		—
Discontinued operations:						
Operating cash flow		1.8		25.3		33.4
Divestiture proceeds		155.1		87.6		—
Capital expenditures		(2.1)		(13.5)		(22.5)
Contributions from (distributions to) owners		(170.4)		(91.9)		(34.8)
Net change in cash		(15.6)		7.5		(23.9)
Total change in cash	$	(15.6)	$	7.5	$	(23.9)

Midstream Holdings' Sources and Uses of Cash—Continuing Operations. Operating cash flow has been a significant source of liquidity. Generally, operating cash flow will increase or decrease due to the same factors that cause increases and decreases in operating margin. Consequently, changes in operating cash flow since 2011 are primarily driven by the fluctuations in volume and price described previously in results of operations.

Historically, operating cash flow has been used to fund capital expenditures. Since 2011, the Predecessor completed several capital expansion activities, including the expansions of the Cana system and Barnett assets in 2013.

Because Midstream Holdings' continuing operations had no separate cash accounts, the owner contributions and distributions represent the net amount of all transactions that were settled with adjustments to equity.

Other, net uses and sources since 2011 largely pertain to the Predecessor's equity investment in Gulf Coast Fractionators. During the years ended December 31, 2012 and 2011, the Predecessor made contributions related to this investment of $16.8 million and $21.1 million, respectively.

Midstream Holdings' Sources and Uses of Cash—Discontinued Operations. Operating cash flow has decreased since 2011 largely due to declining throughput resulting from asset divestitures. In 2013, the Predecessor sold its controlling interest in its assets and operations located in Wyoming for approximately $148 million. In 2012, the Predecessor sold the West Johnson County system for $87 million. The Predecessor also received proceeds in 2013 and 2010 for other minor divestitures. These divestitures also contributed to the general decline in capital expenditures since 2011.

During the years ended 2013 and 2011, the Predecessor made cash distributions to non-controlling interests of $2.9 million, $5.4 million, respectively. During the year ended 2012, the Predecessor received cash contributions from non-controlling interests of $2.3 million, respectively. The remaining owner contributions and distributions in the table above represent the net amount of all other transactions that were settled with adjustments to equity.

Off-Balance Sheet Arrangements. We had no off-balance sheet arrangements as of December 31, 2013, 2012 and 2011.

Contractual Obligations

A summary of contractual obligations as of December 31, 2013 is provided in the following table:

	Payments Due by Period									
		Total		Less Than 1 Year		1-3 Years		3-5 Years		More Than 5 Years
						(in millions)				
Lease obligations (1)	$	8.1	$	7.4	$	0.7	$	—	$	—
Rights-of-way (2)		1.0		0.1		0.2		0.2		0.5
Purchase commitments (3)		3.9		3.9		—		—		—

Asset retirement obligations (4)	14.9	0.1	0.1	0.1	14.6
Total	$ 28.0	$ 11.6	$ 1.0	$ 0.3	$ 15.1

(1) Lease obligations consist of non-cancelable operating leases for equipment and office space used in daily operations.
(2) Right-of-way payments are estimated to approximate $0.1 million per year for the next ten years. Payments for rights-of-way will be required as long as Midstream Holdings' systems are in use, which may be more or less than the ten years we have assumed for this disclosure.
(3) Purchase commitments include commitments to purchase materials in connection with Midstream Holdings' projects to construct new facilities or expand existing facilities.
(4) Asset retirement obligations represent the estimated discounted costs for future dismantlement, abandonment and rehabilitation costs. These obligations are recorded as liabilities on Midstream Holdings' December 31, 2013 balance sheet.

Capital Requirements

Our 2014 capital budget includes approximately $300.0 million of identified growth projects including capitalized interest. Our primary capital projects for 2014 include the expansion of the Cajun-Sibon NGL Pipeline Phase II and construction of our Bearkat plant facilities. During 2013, we invested in several capital projects which primarily included the expansion of the Cajun-Sibon NGL Pipeline. See "Exhibit 99.1. Business—Recent Growth Developments" for further details.

We expect to fund our 2014 maintenance capital expenditures of approximately $65.0 million from operating cash flows. We expect to fund the growth capital expenditures from the proceeds of borrowings under our credit facility discussed below and proceeds from other debt and equity sources. In 2014, it is possible that not all of the planned projects will be commenced or completed. Our ability to pay distributions to our unitholders, and to fund planned capital expenditures and to make acquisitions will depend upon our future operating performance, which will be affected by prevailing economic conditions in the industry and financial, business and other factors, some of which are beyond our control.

Indebtedness

Credit Facility. On February 20, 2014, we entered into a new $1.0 billion unsecured revolving credit facility, which includes a $500.0 million letter of credit subfacility (the "credit facility"). The new credit facility replaced our previous credit facility. The credit facility will mature on the fifth anniversary of the initial funding date, which was March 7, 2014, unless we request, and the requisite lenders agree, to extend it pursuant to its terms. The credit facility contains certain financial, operational and legal covenants. Among other things, these covenants include maintaining a ratio of consolidated indebtedness to consolidated EBITDA (as defined in the credit facility, which definition includes projected EBITDA from certain capital expansion projects) of no more than 5.0 to 1.0. If we consummate one or more acquisitions in which the aggregate purchase price is $50.0 million or more, the maximum allowed ratio of consolidated indebtedness to consolidated EBITDA will increase to 5.5 to 1.0 for the quarter of the acquisition and the three following quarters.

Borrowings under the credit facility bear interest at our option at the Eurodollar Rate (the LIBOR Rate) plus an applicable margin or the Base Rate (the highest of the Federal Funds Rate plus 0.50%, the 30-day Eurodollar Rate plus 1.0%, or the administrative agent's prime rate) plus an applicable margin. The applicable margins vary depending on our credit rating. Upon breach by us of certain covenants governing the credit facility, amounts outstanding under the credit facility, if any, may become due and payable immediately.

Senior Unsecured Notes. On February 10, 2010, we issued, together with Crosstex Energy Finance Corporation, $725.0 million in aggregate principal amount of 8.875% senior unsecured notes (the "2018 Notes") due on February 15, 2018 at an issue price of 97.907% to yield 9.25% to maturity including the original issue discount (OID). Interest payments on the 2018 Notes are due semi-annually in arrears in February and August. On May 24, 2012, we issued, together with Crosstex Energy Finance Corporation, $250.0 million in aggregate principal amount of 7.125% senior unsecured notes (the "2022 Notes" and together with the 2018 Notes, the "Senior Notes") due on June 1, 2022 at an issue price of 100% of the principal amount to yield 7.125% to maturity. The interest payments on the 2022 Notes are due semi-annually in arrears in June and December.

The indentures governing the Senior Notes contain covenants that, among other things, limit our ability to:

- sell assets including equity interests in our subsidiaries;
- pay distributions on, redeem or repurchase units or redeem or repurchase our subordinated debt (as discussed in more detail below);
- make investments;
- incur or guarantee additional indebtedness or issue preferred units;
- create or incur certain liens;
- consolidate, merge or transfer all or substantially all of our assets;
- engage in transactions with affiliates;
- enter into sale and leaseback transactions; or
- engage in certain business activities.

The indentures provide that if our fixed charge coverage ratio (the ratio of consolidated cash flow to fixed charges, which generally represents the ratio of adjusted EBITDA to interest charges with further adjustments as defined per the indenture) for the most recently ended four full fiscal quarters is not less than 2.0 to 1.0, we will be permitted to pay distributions to our unitholders in an amount equal to available cash from operating surplus (each as defined in our partnership agreement) with respect to our preceding fiscal quarter plus a number of items, including the net cash proceeds received by us as a capital contribution or from the issuance of equity interests since the date of the indenture, to the extent not previously expended. If our fixed charge coverage ratio is less than 2.0 to 1.0, we will be able to pay distributions to our unitholders in an amount equal to a specified basket (less amounts previously expended pursuant to such basket), plus the same number of items discussed in the preceding sentence to the extent not previously expended. We expect to be in compliance with this covenant for at least the next twelve months.

If the Senior Notes achieve an investment grade rating from each of Moody's Investors Service, Inc. and Standard & Poor's Ratings Services, many of the covenants discussed above will terminate.

We may redeem all or a part of the 2018 Notes at redemption prices (expressed as percentages of principal amount) equal to 104.438% for the twelve-month period beginning on February 15, 2014, 102.219% for the twelve-month period beginning February 15, 2015 and 100.00% for the twelve-month period beginning on February 15, 2016 and at any time thereafter, plus accrued and unpaid interest, if any, to the applicable redemption date on the notes.

We may redeem up to 35% of the 2022 Notes at any time prior to June 1, 2015 in an amount not greater than the cash proceeds from one or more equity offerings at a redemption price of 107.125% of the principal amount of the 2022 Notes (plus accrued and unpaid interest to the redemption date) provided that

- at least 65% of the aggregate principal amount of the 2022 Notes remains outstanding immediately after the occurrence of such redemption; and
- the redemption occurs within 180 days of the date of the closing of the equity offering.

Pursuant to the foregoing, on January 3, 2014, we instructed the trustee to deliver a notice of redemption for approximately $53.5 million in aggregate principal amount of the 2022 Notes (the "Redeemed Notes"), representing approximately 21% of the aggregate principal amount of the outstanding 2022 Notes. The Redeemed Notes were redeemed effective as of February 2, 2014 for a total redemption price equal to $1,083 per $1,000 principal amount redeemed. Following the completion of the redemption, approximately $196.5 million aggregate principal amount of the 2022 Notes remain outstanding.

Prior to June 1, 2017, we may redeem all or a part of the remaining 2022 Notes at the redemption price equal to the sum of the principal amount thereof, plus a make-whole premium at the redemption date, plus accrued and unpaid interest to the redemption date.

On or after June 1, 2017, we may redeem all or a part of the remaining 2022 Notes at redemption prices (expressed as percentages of principal amount) equal to 103.563% for the twelve-month period beginning on June 1, 2017, 102.375% for the twelve-month period beginning on June 1, 2018, 101.188% for the twelve-month period beginning on June 1, 2019 and 100.000% for the twelve-month period beginning on June 1, 2020 and at any time thereafter, plus accrued and unpaid interest, if any, to the applicable redemption date on the 2022 Notes.

Each of the following is an event of default under the indentures:

- failure to pay any principal or interest when due;
- failure to observe any other agreement, obligation or other covenant in the indenture, subject to the cure periods for certain failures;
- our default under other indebtedness that exceeds a certain threshold amount;
- failures by us to pay final judgments that exceed a certain threshold amount; and
- bankruptcy or other insolvency events involving us.

If an event of default relating to bankruptcy or other insolvency events occurs, the Senior Notes will immediately become due and payable. If any other event of default exists under the indenture, the trustee under the indenture or the holders of the Senior Notes may accelerate the maturity of the Senior Notes and exercise other rights and remedies.

Successful completion of the Acquisition triggered a mandatory repurchase offer under the terms of the indenture governing the 2018 Notes at a purchase price equal to 101% of the aggregate principal amount of the 2018 Notes repurchased, plus accrued and unpaid interest, if any. In certain circumstances, the completion of the business combination also could trigger a mandatory repurchase offer under the terms of the indenture the 2022 Notes if, within 90 days of consummation of the transactions, we experience a rating downgrade of the 2022 Notes by either Moody's or S&P. We intend to fulfill our obligations with respect to the mandatory repurchase offer of the 2018 Notes and, if necessary, the 2022 Notes, in accordance with the terms of the applicable indenture.

Certain Relationships and Related Party Transactions

Our General Partner. Our General Partner does not receive any management fee or other compensation in connection with its management of our business, but it is reimbursed for all direct and indirect expenses incurred on our behalf.

Our General Partner owns the general partner interest in us and all of our incentive distribution rights. Our General Partner is entitled to receive incentive distributions if the amount we distribute with respect to any quarter exceeds levels specified in our partnership agreement. Under the quarterly incentive distribution provisions, generally our General Partner is entitled to 13.0% of amounts we distribute in excess of $0.25 per unit, 23% of the amounts we distribute in excess of $0.3125 per unit and 48.0% of amounts we distribute in excess of $0.375 per unit.

Relationship with Devon and ENLC. ENLC indirectly owns 16,414,830 common units, representing an approximate 7.1% limited partnership interest in us as of March 7, 2014. ENLC also indirectly owns our General Partner and has the power to appoint all of the officers and directors of our General Partner. ENLC is managed by its managing member, which is wholly-owned by Devon. Therefore, Devon indirectly controls our General Partner, which has the sole authority to

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manage and operate our business. Devon also indirectly owns 120,542,441 Class B units, representing an approximate 52% limited partnership interest in us as of March 7, 2014. Accordingly, through its control of our General Partner and majority ownership of our outstanding equity interests, Devon effectively has the ability to veto some of our actions and to control our management.

Additionally, four of our directors, including John Richels, the chairman of our board of directors, David Hager, Thomas Mitchell and Darryl Smette, are officers of Devon. Those individuals do not receive separate compensation for their service on our board of directors, but they are entitled to indemnification related to their service as directors pursuant to the indemnification agreements as described below.

Reimbursement of Costs. ENLC pays us for administrative and compensation costs that we incur on its behalf. We anticipate that during 2014, this cost reimbursement will be between $12.0 million to $15.0 million.

Commercial Arrangements

Midstream Holdings, in which we hold a 50% economic interest as of March 7, 2014, conducts business with Devon pursuant to gathering and processing agreements described below. We also historically have maintained a relationship with Devon as a customer, as described in more detail below.

Gathering and Processing Agreements

As described elsewhere, Midstream Holdings was previously a wholly-owned subsidiary of Devon, and all of its assets were contributed to it by Devon. In connection with the consummation of the business combination, Midstream Holdings entered into gathering and processing agreements with certain subsidiaries of Devon pursuant to which Midstream Holdings provides gathering, treating, compression, dehydration, stabilization, processing and fractionation services, as applicable, for natural gas delivered by Devon to Midstream Holdings gathering systems in the Barnett, Cana-Woodford and Arkoma-Woodford Shales. These agreements provide Midstream Holdings with dedication of all of the natural gas owned or controlled by Devon and produced from or attributable to existing and future wells located on certain oil, natural gas and mineral leases covering lands within the acreage dedications, excluding properties previously dedicated to other natural gas gathering systems not owned and operated by Devon.

Pursuant to the gathering and processing agreements, Devon has committed to deliver specified average minimum daily volumes of natural gas to Midstream Holdings' gathering systems in the Barnett, Cana-Woodford and Arkoma-Woodford Shales during each calendar quarter for a five-year period following execution. These commitments account for substantially all of Midstream Holdings' natural gas supply and approximately 21.5% of our combined revenues, or $547.8 million, on a pro forma basis for the year ended December 31, 2013. Devon is entitled to firm service, meaning that if capacity on a system is curtailed or reduced, or capacity is otherwise insufficient, Midstream Holdings will take delivery of as much Devon natural gas as is permitted in accordance with applicable law.

The gathering and processing agreements are fee-based, and Midstream Holdings is paid a specified fee per MMBtu for natural gas gathered on Midstream Holdings' gathering systems and a specified fee for natural gas processed. The particular fees, all of which are subject to an automatic annual inflation escalator at the beginning of each year, differ from one system to another and do not contain a fee redetermination clause.

Please see "Exhibit 99.2—Risk Factors" for a description of the risks associated with our dependence on Devon pursuant to these agreements.

Historical Customer Relationship with Devon

As noted above, we have historically maintained a customer relationship with Devon pursuant to which certain of our subsidiaries provide gathering, transportation, processing and gas lift services to Devon subsidiaries in exchange for fee-based compensation under several agreements with such Devon subsidiaries. The terms of these agreements vary, but the agreements expire between July 2014 and July 2021 and they automatically renew for month-to-month or year-to-year periods unless canceled by Devon prior to expiration. In addition, one of our subsidiaries has agreements with a subsidiary of Devon pursuant to which our subsidiary purchases and sells NGLs and pays or receives, as applicable, a margin-based fee. These NGL purchase and sale agreements have either month-to-month terms or expire in July 2014, depending on the agreement, but none renews automatically. These historical agreements collectively comprise $72.2 million, or 2.8%, of combined revenue on a pro forma basis for the year ended December 31, 2013.

Transition Services Agreement

In connection with the consummation of the business combination, we entered into a transition services agreement with Devon pursuant to which Devon will provide certain services to us with respect to the business and operations of Midstream Holdings, including IT, accounting, pipeline integrity, compliance management and procurement services, and we will provide certain services to Devon and its subsidiaries, including IT, human resources and other commercial and operational services. We expect this agreement will have minimal to no impact on our annual revenue.

GCF Agreement

In connection with the consummation of the business combination, Midstream Holdings entered into an agreement with a wholly-owned subsidiary of Devon pursuant to which Devon agreed, from and after the closing of the business combination, to hold for the benefit of Midstream Holdings the economic benefits and burdens of Devon's 38.75% general partner interest in Gulf Coast Fractionators in Mont Belvieu, Texas. We expect this agreement to contribute approximately $12.0 million to our income from equity investments for fiscal year 2014.

Lone Camp Gas Storage Agreement

In connection with the consummation of the business combination, Midstream Holdings entered into an agreement with a wholly-owned subsidiary of Devon under which Midstream Holdings will provide gas storage services at its Lone Camp storage facility. Under this agreement, the wholly-owned subsidiary of Devon will reimburse Midstream Services for the expenses it incurs in providing the storage services. We expect this agreement will have minimal to no impact on our annual revenue.

Acacia Transportation Agreement

In connection with the consummation of the business combination, a subsidiary of Midstream Holdings entered into an agreement with a wholly-owned subsidiary of Devon pursuant to which Midstream Holdings provides transportation services to Devon on its Acacia line. This agreement accounted for approximately 0.6% of our combined revenues, or $14.4 million, on a pro forma basis for the year ended December 31, 2013.

Office Leases

In connection with the consummation of the business combination, we entered into three office lease agreements with a wholly-owned subsidiary of Devon pursuant to which we will lease office space at Devon's Bridgeport, Oklahoma City and Cresson office buildings. Rent payable to Devon under these lease agreements is $174,000, $31,000 and $66,000, respectively, on an annual basis.

Preferential Rights Agreement

Upon the closing of the business combination, we entered into a preferential rights agreement with ENLC and CEI, pursuant to which ENLC and CEI granted us a right of first refusal, for a period of 10 years, with respect to (i) CEI's interest in E2, and (ii) Devon's 50% interest in the Access Pipeline transportation system (the "Access Pipeline Interest"), to the extent ENLC in the future obtains such interest pursuant to a first offer agreement between Devon and ENLC. In addition, if ENLC has the opportunity to exercise its right of first offer for the Access Pipeline Interest pursuant to the first offer agreement but determines not to exercise such right, it will be required to assign such right to us.

Tax Sharing Agreement

In connection with the Contribution Closing, the Partnership, ENLC and Devon entered into a tax sharing agreement providing for the allocation of responsibilities, liabilities and benefits relating to any tax for which a combined tax return is due. In 2013, ENLC and Devon incurred approximately $3.0 million in taxes that would have been subject to the tax sharing agreement, had it been effective.

Indemnification of Directors and Officers

Under our partnership agreement, in most circumstances, we will, to the fullest extent permitted by law, indemnify and hold harmless the following persons from and against all losses, claims, damages or similar events:

- our General Partner;
- any departing general partner;

- any person who is or was an affiliate of our General Partner or any departing general partner;
- any person who is or was a director, officer, member, partner, fiduciary or trustee of any entity set forth in the preceding three bullet points;

- any person who is or was serving as director, officer, member, partner, fiduciary or trustee of another person at the request of our General Partner or any departing general partner; and
- any person designated by our General Partner.

Any indemnification under these provisions will only be out of our assets. Unless it otherwise agrees, our General Partner will not be liable for, or have any obligation to contribute or lend funds or assets to us to enable us to effectuate, indemnification. We may purchase insurance against liabilities asserted against and expenses incurred by persons for our activities, regardless of whether we would have the power to indemnify the person against liabilities under our partnership agreement.

We have entered into indemnification agreements (the “Indemnification Agreements”) with each of our General Partner’s directors and executive officers (collectively, the “Indemnitees”). Under the terms of the Indemnification Agreements, we agree to indemnify and hold each Indemnitee harmless, subject to certain conditions, against any and all losses, claims, damages, liabilities, expenses (including legal fees and expenses), judgments, fines, ERISA excise taxes, penalties, interest, settlements or other amounts arising from any and all threatened, pending or completed claims, demands, actions, suits or proceedings, whether civil, criminal, administrative or investigative, and whether formal or informal and including appeals (each, a “Proceeding”), in which the Indemnitee is involved, or is threatened to be involved, as a party or otherwise, because the Indemnitee is or was a director, manager or officer of the General Partner or us, or is or was serving at the request of the General Partner or us as a manager, managing member, general partner, director, officer, fiduciary, or trustee of another entity, organization or person of any nature. To the extent that a change in the laws of the State of Delaware permits greater indemnification under any statute, agreement, organizational document or governing document than would be afforded under the Indemnification Agreements as of the date of the Indemnification Agreements, the Indemnitee shall enjoy the greater benefits so afforded by such change.

Approval and Review of Related Party Transactions If we contemplate entering into a transaction, other than a routine or in the ordinary course of business transaction, in which a related person will have a direct or indirect material interest, the proposed transaction is submitted for consideration to the Board or our senior management, as appropriate. If the Board is involved in the approval process, it determines whether it is advisable to refer the matter to the Conflicts Committee of the Board, comprised entirely of independent directors, as constituted under our limited partnership agreement. The Conflicts Committee operates pursuant to its written charter and our partnership agreement. If a matter is referred to the Conflicts Committee, the Conflicts Committee obtains information regarding the proposed transaction from management and determines whether it is advisable to engage independent legal counsel or an independent financial advisor to advise the members of the committee regarding the transaction. If the committee retains such counsel or financial advisor, it considers the advice and, in the case of a financial advisor, such advisor’s opinion as to whether the transaction is fair and reasonable to us and to our unitholders.

Disclosure Regarding Forward-Looking Statements

This report contains forward-looking statements that are based on information currently available to management as well as management’s assumptions and beliefs. All statements, other than statements of historical fact, included herein constitute forward-looking statements, including but not limited to statements identified by the words “forecast,” “may,” “believe,” “will,” “should,” “plan,” “predict,” “anticipate,” “intend,” “estimate” and “expect” and similar expressions. Such statements reflect our current views with respect to future events, based on what we believe are reasonable assumptions; however, such statements are subject to certain risks and uncertainties. In addition to the specific uncertainties discussed elsewhere in this report, the risk factors set forth in “Exhibit 99.2 Risk Factors” may affect our performance and results of operations. Should one or more of these risks or uncertainties materialize, or should underlying assumptions prove incorrect, actual results may differ materially from those in the forward-looking statements. We disclaim any intention or obligation to update or review any forward-looking statements or information, whether as a result of new information, future events or otherwise.

Exhibit 99.4

INDEX TO FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors
Devon Energy Corporation:

We have audited the accompanying combined balance sheets of EnLink Midstream Holdings, LP Predecessor (Predecessor) as of December 31, 2013 and 2012, and the related combined statements of operations, equity, and cash flows for each of the years in the three year period ended December 31, 2013. These combined financial statements are the responsibility of the Predecessor's management. Our responsibility is to express an opinion on these combined financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the combined financial statements referred to above present fairly, in all material respects, the financial position of the Predecessor as of December 31, 2013 and 2012, and the results of its operations and its cash flows for each of the years in the three year period ended December 31, 2013, in conformity with U.S. generally accepted accounting principles.

/s/ KPMG LLP

Oklahoma City, Oklahoma
March 7, 2014

ENLINK MIDSTREAM HOLDINGS, LP PREDECESSOR

COMBINED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2013	2012	2011
		(in millions)	
Operating revenues:			
Operating revenues — affiliates	$ 2,180.9	$ 1,816.5	$ 2,325.0
Operating revenues	209.8	184.3	298.4
Total operating revenues	2,390.7	2,000.8	2,623.4
Operating expenses:			
Product purchases — affiliates	1,603.4	1,324.2	1,774.2
Product purchases	170.3	140.3	239.9
Operations and maintenance	125.4	127.2	109.6
Operations and maintenance — affiliates	45.3	43.8	45.9
Depreciation and amortization	199.0	159.8	144.8
General and administrative — affiliates	47.0	43.6	40.1
Non-income taxes	18.0	13.2	15.3
Asset impairments	18.2	50.1	—
Other, net	0.5	(3.0)	(58.0)
Total operating expenses	2,227.1	1,899.2	2,311.8
Operating income	163.6	101.6	311.6
Income from equity investment	14.8	2.0	9.3
Income from continuing operations before income taxes	178.4	103.6	320.9
Income tax expense	64.2	37.3	115.5
Net income from continuing operations	114.2	66.3	205.4
Discontinued operations:			
Net income from discontinued operations	2.6	10.6	12.8
Net income from discontinued operations attributable to non-controlling interests	(1.3)	(1.1)	(2.1)
Net income from discontinued operations attributable to Devon	1.3	9.5	10.7
Net income attributable to Devon	$ 115.5	$ 75.8	$ 216.1

See accompanying notes to the combined financial statements.

ENLINK MIDSTREAM HOLDINGS, LP PREDECESSOR

COMBINED BALANCE SHEETS

	December 31, 2013	December 31, 2012
	(in millions)	
Assets		
Current assets:		
Inventories	$ 2.6	$ 5.5
Prepaid expenses	3.6	4.2
Assets held for sale	—	21.4
Other	0.4	0.3
Total current assets	6.6	31.4
Property, plant and equipment, at cost	3,200.3	2,985.8
Less accumulated depreciation and amortization	(1,359.9)	(1,142.6)
Net property, plant and equipment	1,840.4	1,843.2
Equity investment	61.1	57.7
Goodwill	401.7	401.7
Assets held for sale	—	201.2
Total assets	$ 2,309.8	$ 2,535.2
Liabilities and Equity		
Current liabilities:		
Accrued expenses and other	$ 44.7	$ 80.1
Current liabilities associated with assets held for sale	—	3.3
Total current liabilities	44.7	83.4
Asset retirement obligations	14.9	13.2
Deferred income taxes	466.2	431.8
Other	0.3	4.8
Total liabilities	526.1	533.2
Equity:		
Devon equity	1,783.7	1,953.3
Non-controlling interests	—	48.7
Total equity	1,783.7	2,002.0
Commitments and contingencies (Note 9)		
Total liabilities and equity	$ 2,309.8	$ 2,535.2

See accompanying notes to the combined financial statements.

ENLINK MIDSTREAM HOLDINGS, LP PREDECESSOR

COMBINED STATEMENTS OF EQUITY

	Year Ended December 31, 2013	2012	2011
		(in millions)	
Devon equity			
Balance as of beginning of year	$ 1,953.3	$ 1,856.0	$ 1,800.4
Net income	115.5	75.8	216.1
Net distributions from (to) Devon — continuing operations	(117.6)	115.7	(131.1)
Net distributions to Devon — discontinued operations	(167.5)	(94.2)	(29.4)
Balance as of end of year	$ 1,783.7	$ 1,953.3	$ 1,856.0
Non-controlling interests			
Balance as of beginning of year	$ 48.7	$ 45.3	$ 48.6
Net income	1.3	1.1	2.1
Sale of non-controlling interest	(47.1)	—	—
Net distributions from (to) non-controlling interests — discontinued operations	(2.9)	2.3	(5.4)
Balance as of end of year	$ —	$ 48.7	$ 45.3
Total equity			
Balance as of beginning of year	$ 2,002.0	$ 1,901.3	$ 1,849.0
Net income	116.8	76.9	218.2
Sale of non-controlling interest	(47.1)	—	—
Net distributions from (to) Devon — continuing operations	(117.6)	115.7	(131.1)
Net distributions to Devon and non-controlling interests — discontinued operations	(170.4)	(91.9)	(34.8)
Balance as of end of year	$ 1,783.7	$ 2,002.0	$ 1,901.3

See accompanying notes to the combined financial statements.

ENLINK MIDSTREAM HOLDINGS, LP PREDECESSOR

COMBINED STATEMENTS OF CASH FLOWS

	Year Ended December 31, 2013	2012	2011

	(in millions)		
Cash flows from operating activities:			
Net income from continuing operations	$ 114.2	$ 66.3	$ 205.4
Adjustments to reconcile net income from continuing operations to net cash provided by operating activities:			
Depreciation and amortization	199.0	159.8	144.8
Asset impairments	18.2	50.1	—
Deferred income tax (benefit) expense	34.0	(10.5)	42.0
(Income) loss from equity investment, net of distributions	(2.8)	0.3	(0.9)
Other noncash items, net	1.0	(1.0)	1.9
Changes in assets and liabilities:			
Inventories	2.9	0.5	3.7
Prepaid expenses	0.4	0.1	(1.0)
Other assets	(0.6)	0.5	0.7
Accrued expenses and other liabilities	(5.8)	(11.7)	4.6
Net cash provided by operating activities	360.5	254.4	401.2
Cash used in investing activities:			
Capital expenditures	(243.1)	(351.7)	(247.6)
Contribution to equity investment	—	(16.8)	(21.1)
Other	0.2	—	0.1
Net cash used in investing activities	(242.9)	(368.5)	(268.6)
Cash flows from financing activities:			
Net distributions from (to) Devon	(117.6)	115.7	(131.1)
Other	—	(1.6)	(1.5)
Net cash provided by (used in) financing activities	(117.6)	114.1	(132.6)
Cash flows from discontinued operations:			
Net cash provided by operating activities	1.8	25.3	33.4
Net cash provided by (used in) investing activities	153.0	74.1	(22.5)
Net cash used in financing activities — net distributions to Devon and non-controlling interests	(170.4)	(91.9)	(34.8)
Net cash provided by (used in) discontinued operations	(15.6)	7.5	(23.9)
Net change in cash and cash equivalents	(15.6)	7.5	(23.9)
Beginning cash and cash equivalents — related to assets held for sale	15.6	8.1	32.0
Ending cash and cash equivalents — related to assets held for sale	$ —	$ 15.6	$ 8.1

See accompanying notes to the combined financial statements.

ENLINK MIDSTREAM HOLDINGS, LP PREDECESSOR

NOTES TO COMBINED FINANCIAL STATEMENTS

1. Organization and Nature of Business

On March 7, 2014, Devon Energy Corporation ("Devon"), Crosstex Energy, Inc. and EnLink Midstream Partners, LP (formerly known as Crosstex Energy, L.P.) (collectively "Crosstex") combined the Crosstex assets with certain of Devon's midstream assets, forming a new midstream business (the "Merger"). Following the Merger, two publicly-held entities will exist: EnLink Midstream Partners, LP (the "Partnership") and EnLink Midstream, LLC ("EnLink Midstream"), a master limited partnership and a general partner, respectively.

In exchange for a controlling interest in both EnLink Midstream and the Partnership, Devon contributed its equity interest in EnLink Midstream Holdings, LP ("Midstream Holdings") and $100 million in cash. Midstream Holdings owns Devon's midstream systems serving the Barnett, Cana-Woodford and Arkoma-Woodford Shales in Texas and Oklahoma, as well as a contractual right to the burdens and benefits of a 38.75% economic interest in Gulf Coast Fractionators in Mont Belvieu, Texas. The Partnership and EnLink Midstream each own 50% of Midstream Holdings.

Subsequent to closing the Merger, the ownership of EnLink Midstream is approximately:

- Devon: 70%
- Former Crosstex Energy, Inc. public shareholders: 30%

Subsequent to closing the Merger, the ownership of the Partnership is approximately:

- EnLink Midstream, as general partner: 7%
- Devon: 53%
- Former Crosstex Energy, L.P. public unitholders: 40%

The accompanying financial statements of Enlink Midstream Holdings, LP Predecessor (the "Predecessor") have been prepared in connection with the Merger. The Predecessor is comprised of Devon's U.S. midstream assets and operations, including Devon's 38.75% economic interest in Gulf Coast Fractionators.

The Predecessor is engaged in the business of purchasing natural gas from Devon and third parties at or near the wellhead and then gathering, compressing, treating and processing the purchased natural gas and fractionating the natural gas liquids, or NGLs, that result from the natural gas processing. After performing these activities, the Predecessor sells its natural gas and NGLs to Devon. The Predecessor primarily performs these activities to support Devon's operations. However, to the extent system capacity is available, the Predecessor also provides these services to other companies engaged in the production, distribution and marketing of natural gas and NGLs.

The Predecessor's assets consist of Devon's U.S. natural gas gathering and processing systems, as well as Devon's 38.75% economic interest in Gulf Coast Fractionators. These systems are located primarily in Texas and Oklahoma. The most significant system is the Bridgeport system, which serves the Barnett Shale in North Texas. This system includes integrated gathering pipelines, one gas processing plant and an NGL fractionator. The Cana system serves the Cana-Woodford Shale in West Central Oklahoma. This system consists of integrated gathering pipelines and a gas processing plant. The Northridge system serves the Arkoma-Woodford Shale in Southeastern Oklahoma. This system consists of integrated gathering pipelines and a gas processing plant. Gulf Coast Fractionators is a full-service NGL fractionator located on the Gulf Coast at the Mont Belvieu, Texas hub. The Predecessor's other assets include systems that serve the Powder River Basin in Wyoming and other areas where Devon operates.

2. Summary of Significant Accounting Policies

Basis of Presentation

The Predecessor's accompanying combined financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America on the basis of Devon's historical ownership of the Predecessor's assets and its operations. These financial statements include the Predecessor's accounts and those of its majority-owned subsidiaries. All significant intercompany transactions and balances have been eliminated.

The accompanying financial statements have been prepared from records maintained by Devon and may not be indicative of the actual results of operations that might have occurred if the Predecessor had been operated separately during the periods reported. Because a direct ownership relationship did not exist among the businesses comprising the Predecessor, the net investment in the Predecessor is shown as equity, in lieu of owner's equity, in the combined financial statements.

During the reporting periods for the accompanying financial statements, Devon provided cash management services to the Predecessor through a centralized treasury system. As a result, all revenues covered by the centralized treasury system were deemed to have been received in cash by the Predecessor from Devon during the period in which the revenue was recorded in the financial statements. All charges and cost allocations covered by the centralized treasury system were deemed to have been paid in cash to Devon during the period in which the cost was recorded in the financial statements. The net effects of these amounts are reflected as net distributions to or contributions from Devon and non-controlling interests in the accompanying statements of equity. As a result of this accounting treatment, the Predecessor's working capital does not reflect any affiliate accounts receivables or payables, except for amounts that pertain to planned cash transfers between the Predecessor and Devon affiliates.

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual amounts could differ from these estimates, and changes in these estimates are recorded when known. Significant items subject to such estimates and assumptions include the following:

- reporting unit fair value and the related assessment of goodwill for impairment,
- fair value of property, plant and equipment and the related impairment assessment,
- depreciation of property, plant and equipment,
- allocations of Devon's corporate overhead costs,
- legal and environmental risks and exposures,
- asset retirement obligations, and
- income taxes.

Reportable Segments

The Predecessor's operations are managed through distinct operating segments, which are defined primarily as each natural gas gathering and processing system serving separate geographic regions. For financial reporting purposes, the operating segments are aggregated into one reporting segment due to the similar nature of the businesses.

Revenue Recognition and Gas Balancing

The Predecessor's operating revenues consist of revenues from gathering, compressing, treating and processing natural gas and from fractionating NGLs. Generally, the Predecessor receives fees for the services it provides. For natural gas processing services, the Predecessor receives a percent-of-proceeds fee based on the sales value of extracted NGLs and residue natural gas. For gathering, compression and treating services, the Predecessor receives a fixed fee based on the volume and thermal content of the associated natural gas.

Operating revenues are recorded at the time products are sold or services are provided to Devon or other customers at a fixed or determinable price, delivery or performance has occurred, title has transferred and collectability of the revenue is probable.

Operating revenues and expenses attributable to the Predecessor's natural gas and NGL purchase and processing contracts are reported on a gross basis when the Predecessor takes title to the products and has risks and rewards of ownership. The natural gas purchased under these contracts is processed in the Predecessor's processing facilities.

Allocation of Costs

Certain of Devon's centralized overhead and operating costs represent shared services that benefit its subsidiaries and affiliates, including the Predecessor. The shared services consist primarily of accounting, treasury, information technology, human resources, legal and facilities management. The accompanying financial statements include costs allocated by Devon for these shared services in the form of a management services fee. The costs are allocated to the Predecessor based on its proportionate share of Devon's revenues, employee compensation and gross property, plant and equipment. Management believes these allocation methodologies are reasonable. All allocated costs are included in general and administrative expenses in the accompanying combined statements of operations.

Devon grants certain share-based awards to members of its Board of Directors and selected employees. The Predecessor does not grant share-based awards but does participate in Devon's share-based award plans. The awards granted under Devon's plans are measured at fair value on the date of grant and are recognized as expense over the applicable requisite service periods.

The Predecessor does not sponsor any pension, postretirement or employee savings plans. However, the Predecessor participates in certain plans sponsored by Devon. The Predecessor participates in Devon's non-contributory defined benefit pension plans, including both qualified and nonqualified plans. Devon also has defined benefit postretirement plans that provide medical and, in some cases, life insurance benefits, in which the Predecessor participates. Devon also sponsors, and the Predecessor participates in, 401(k) and enhanced contribution plans to which Devon makes contributions to participant accounts.

Income Taxes

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

In addition, the Predecessor accounts for deferred income taxes related to the federal and state jurisdictions using the asset and liability method. Under this method, deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of assets and liabilities and their respective tax bases. Deferred tax assets are also recognized for the future tax benefits attributable to the expected utilization of existing tax net operating loss carryforwards and other types of carryforwards. If the future utilization of some portion of carryforwards is determined to be unlikely, a valuation allowance is provided to reduce the recorded tax benefits from such assets. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences and carryforwards are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date.

The Predecessor recognizes the financial statement effects of tax positions when it is more likely than not, based on the technical merits, that the position will be sustained upon examination by a taxing authority. Recognized tax positions are initially and subsequently measured as the largest amount of tax benefit that is more likely than not of being realized upon ultimate settlement with a taxing authority. Liabilities for unrecognized tax benefits are presented as other current or long-term liabilities in the accompanying balance sheet based on timing of the expected settlement. Interest and penalties related to unrecognized tax benefits are included in current income tax expense.

In connection with the mergers, the Predecessor's operations will be structured so that none of its operations will be subject to income tax, except for the operations subject to the Texas gross margin tax. Accordingly, Midstream Holdings, including its subsidiaries, will no longer be subject to corporate federal income taxes.

Discontinued Operations

The Predecessor classifies as discontinued operations its assets or asset groups that have clearly distinguishable cash flows and are in the process of being sold or have been sold.

Cash and Cash Equivalents

The Predecessor considers all highly liquid investments with original contractual maturities of three months or less to be cash equivalents. Under the Predecessor's cash management arrangement with Devon, the Predecessor remits all excess cash to Devon who then funds the Predecessor's controlled disbursement accounts as amounts are presented for payment. There were no outstanding checks in excess of cash balances as of December 31, 2013.

Inventories

Inventories consist of materials and supplies used in the Predecessor's operations. All inventories are recorded at the lower of the weighted average cost or market value.

Property, Plant and Equipment

Costs directly and indirectly related to the acquisition or construction of the Predecessor's processing facilities, pipelines and equipment are capitalized and recorded as property, plant and equipment. Direct costs include labor and material costs. Indirect costs include taxes, fees, the cost of funds used during construction and other various costs. Improvement costs which extend the useful lives or increase the capacity of these assets are also capitalized. Repair and maintenance costs which do not increase the useful lives or capacity of these assets are recognized as operations and maintenance expense in the accompanying statements of operations.

Costs for property, plant and equipment that are in use are depreciated over the assets' estimated useful lives, using either the units-of-production or straight-line method.

Upon the disposition or retirement of property, plant and equipment related to continuing operations, any gain or loss is recognized as other income or expense in the statement of operations. When a disposition or retirement occurs which qualifies as discontinued operations, any gain or loss is recognized as income or loss from discontinued operations in the statement of operations.

The Predecessor evaluates its property, plant and equipment for potential impairment whenever events or changes in circumstances indicate that the carrying amount of the assets may not be recoverable. The carrying amount of a long-lived asset is not recoverable when it exceeds the undiscounted sum of the cash flows expected to result from the use and eventual disposition of the asset. Estimates of expected future cash flows represent management's best estimate based on reasonable and supportable assumptions. When the carrying amount of a long-lived asset is not recoverable, an impairment loss is recognized equal to the excess of the asset's carrying value over its fair value. The fair values of long-lived assets are generally determined from estimated discounted future net cash flows. The fair value of the predecessor's long-lived assets is considered a level 3 fair value measurement. Estimated future net cash flows are highly dependent on the duration of expected cash flows and estimated future natural gas and NGL pricing, operating costs, capital expenditures and throughput volumes.

Equity Method of Accounting

The Predecessor accounts for investments it does not control but has the ability to exercise significant influence using the equity method of accounting. Under this method, equity investments are carried originally at the acquisition cost, increased by the Predecessor's proportionate share of the investee's net income and by contributions made, and decreased by the Predecessor's proportionate share of the investee's net losses and by distributions received.

The Predecessor evaluates its equity investments for potential impairment whenever events or changes in circumstances indicate that the carrying amount of the investments may not be recoverable.

Goodwill

Goodwill represents the excess of the purchase price of business combinations over the fair value of the net assets acquired. Goodwill is tested at least annually for impairment. The impairment test requires allocating goodwill and all other assets and liabilities to assigned reporting units. The fair value of each reporting unit is estimated and compared to the net book value of the reporting unit. If the estimated fair value of the reporting unit is less than the net book value, including goodwill, then the goodwill is written down to the implied fair value of the goodwill through a charge to expense. Because quoted market prices are not available for the Predecessor's reporting unit, the fair value of the reporting unit is estimated using valuation analyses based on values of comparable companies and comparable transactions. The Predecessor performed annual impairment tests of goodwill as of the fourth quarters of 2013, 2012 and 2011. Based on these assessments, no impairment of goodwill was required.

Asset Retirement Obligations

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

Commitments and Contingencies

Liabilities for loss contingencies arising from claims, assessments, litigation or other sources are recorded when it is probable that a liability has been incurred and the amount can be reasonably estimated. Liabilities for environmental remediation or restoration claims resulting from improper operation of assets are recorded when it is probable that an obligation has been incurred and the

amount can be reasonably estimated. Expenditures related to such environmental matters are expensed or capitalized in accordance with the Predecessor's accounting policy for property, plant and equipment.

3. Affiliate Transactions

The Predecessor engages in various transactions with Devon and other affiliated entities. These transactions relate to sales to and from affiliates, services provided by affiliates, cost allocations from affiliates and centralized cash management activities performed by affiliates. Management believes these transactions are executed on terms that are fair and reasonable and are consistent with terms for transactions with nonaffiliated third parties. The amounts related to affiliate transactions are specified in the accompanying financial statements.

The following schedule presents the affiliate transactions and other transactions made to or received from Devon, all of which are settled through an adjustment to equity:

	Year Ended December 31, 2013	2012	2011
		(in millions)	
Continuing operations:			
Operating revenues — affiliates	$ (2,180.9)	$ (1,816.5)	$ (2,325.0)
Operating expenses — affiliates	1,695.7	1,411.6	1,860.2
Net affiliate transactions	(485.2)	(404.9)	(464.8)
Capital expenditures	243.1	351.7	247.6
Other third-party transactions, net	124.5	168.9	86.1
Total third-party transactions	367.6	520.6	333.7
Net distributions from (to) Devon — continuing operations	$ (117.6)	$ 115.7	$ (131.1)
Discontinued operations:			
Operating revenues — affiliates	$ (20.2)	$ (89.5)	$ (152.3)
Operating expenses — affiliates	6.5	60.3	107.6
Cash used in financing activities — affiliates	(5.6)	(1.1)	(24.7)
Net affiliate transactions	(19.3)	(30.3)	(69.4)
Capital expenditures	2.1	13.5	22.5
Other third-party transactions, net	(153.2)	(75.1)	12.1
Net third-party transactions	(151.1)	(61.6)	34.6
Net distributions to Devon and non-controlling interests — discontinued operations	$ (170.4)	$ (91.9)	$ (34.8)

During 2013, 2012 and 2011, Devon was the Predecessor's only significant customer. Devon accounted for 91% of the Predecessor's operating revenues for both 2013 and 2012 and 89% for 2011.

Share-based compensation costs included in the management services fee charged to the Predecessor by Devon were approximately $12.8 million for both 2013 and 2012 and $12.6 million for 2011. Pension, postretirement and employee savings plan costs included in the management services fee charged to the Predecessor by Devon were approximately $8.7 million, $9.1 million, and $8.3 million for 2013, 2012 and 2011, respectively. These amounts are included in general and administrative expenses in the accompanying statements of operations.

4. Other, net

During 2013, the Predecessor recognized $0.5 million of net other expense. During 2012 and 2011, the Predecessor recognized $3.0 million and $58.0 million of net other income, respectively. In 2012, the Predecessor received insurance proceeds of $5.6 million related to business interruption that occurred at Gulf Coast Fractionators. In 2011, the Predecessor received $57.8 million of excess insurance recoveries related to business interruption and equipment damage at its Cana system that resulted from tornadoes.

5. Income Taxes

Income Tax Expense

The Predecessor is a member of an affiliated group that files consolidated income tax returns. Income taxes are calculated based on each entity's separate taxable income or loss. The components of income tax expense related to the Predecessor's income from continuing operations are as follows:

	Year Ended December 31, 2013	2012	2011
	(in millions)		
Current income tax expense:			
U.S. federal	$ 29.3	$ 46.2	$ 71.4
Various states	0.9	1.6	2.1
Total current tax expense	30.2	47.8	73.5
Deferred income tax expense (benefit):			
U.S. federal	33.1	(10.2)	40.8
Various states	0.9	(0.3)	1.2
Total deferred tax expense (benefit)	34.0	(10.5)	42.0
Total income tax expense	$ 64.2	$ 37.3	$ 115.5

The following schedule reconciles the Predecessor's total income tax expense and the amount computed by applying the statutory U.S. federal tax rate to income from continuing operations before income taxes:

	Year Ended December 31, 2013	2012	2011
	(in millions)		
Expected income tax expense based on federal statutory rate of 35%	$ 62.4	$ 36.0	$ 112.2
State income taxes, net of federal benefit and other	1.8	1.3	3.3
Total income tax expense	$ 64.2	$ 37.3	$ 115.5

Deferred Tax Assets and Liabilities

The tax effects of temporary differences that gave rise to significant portions of the Predecessor's deferred tax assets and liabilities are presented below:

	December 31, 2013	2012
	(in millions)	
Deferred tax assets:		
Asset retirement obligations	$ 4.6	$ 4.2
Other	0.5	0.1
Total deferred tax assets	5.1	4.3
Deferred tax liabilities:		
Property, plant and equipment	(471.3)	(435.4)
Other	—	(0.7)
Total deferred tax liabilities	(471.3)	(436.1)
Deferred tax liability, net	$ (466.2)	$ (431.8)

Unrecognized Tax Benefits

For the years ended December 31, 2013, 2012 and 2011, the Predecessor had not recorded any amounts related to unrecognized tax benefits. Included below is a summary of the tax years that remain subject to examination by taxing authorities:

Jurisdiction	Tax Years Open
U.S. federal	2008-2013
Various U.S. states	2008-2013

6. Discontinued Operations

The following schedule summarizes net income for Predecessor's discontinued operations:

	Year Ended December 31, 2013	2012	2011
	(in millions)		
Operating revenues:			
Operating revenues	$ 11.6	$ 22.6	$ 20.4
Operating revenues — affiliates	20.2	89.5	152.3
Total operating revenues	31.8	112.1	172.7

Operating expenses:			
Operating expenses	17.4	40.9	38.3
Operating expenses — affiliates	6.6	60.3	107.6
Asset impairments	2.2	3.0	6.8
(Gain) loss on sale of assets, net	1.6	(8.7)	—
Total operating expenses	27.8	95.5	152.7
Income before income taxes	4.0	16.6	20.0
Income tax expense	1.4	6.0	7.2
Net income	2.6	10.6	12.8
Net income attributable to non-controlling interests	(1.3)	(1.1)	(2.1)
Net income attributable to Devon	$ 1.3	$ 9.5	$ 10.7

The following schedule presents the main classes of assets and liabilities associated with Predecessor's discontinued operations. There were no assets and liabilities associated with discontinued operations as of December 31, 2013:

	December 31, 2012
	(in millions)
Cash and cash equivalents	$ 15.6
Accounts receivable	3.7
Inventories	2.0
Other current assets	0.1
Total current assets	21.4
Property, plant and equipment	184.7
Goodwill	16.5
Total assets	$ 222.6
Accounts payable	$ 2.8
Other current liabilities	0.5
Total current liabilities	3.3
Asset retirement obligations	4.2
Other long-term liabilities	0.3
Total liabilities	$ 7.8
Non-controlling interests in equity	$ 48.7

7. Property, Plant and Equipment

The components of property, plant and equipment are as follows:

	December 31,	
	2013	2012
	(in millions)	
Pipelines	$ 1,921.9	$ 1,817.2
Processing facilities	1,270.2	1,160.0
Other	8.2	8.6
Property, plant and equipment	3,200.3	2,985.8
Accumulated depreciation and amortization	(1,359.9)	(1,142.6)
Property, plant and equipment, net	$ 1,840.4	$ 1,843.2

During 2013 and 2012, the Predecessor recognized $18.2 million and $50.1 million, respectively, of asset impairments related to its continuing operations. The impairments resulted from the impact of lower natural gas and NGL prices on the Predecessor's Northridge system and other less significant systems.

8. Asset Retirement Obligations

The schedule below summarizes the changes in the Predecessor's asset retirement obligations:

	Year Ended December 31,	
	2013	2012
	(in millions)	
Beginning asset retirement obligations	$ 13.2	$ 11.8
Revisions to existing liabilities	1.0	0.2
Liabilities incurred	—	0.5
Accretion	0.7	0.7
Ending asset retirement obligations	$ 14.9	$ 13.2

9. Commitments and Contingencies

Commitments

The Predecessor leases certain equipment and office space under operating lease arrangements. Total rental expense recognized under these operating leases was $21.7 million, $27.8 million and $25.9 million in 2013, 2012 and 2011, respectively.

In addition to its operating leases, the Predecessor has rights-of-way commitments that have remaining non-cancelable terms in excess of one year. The following schedule includes these long-term commitments and short-term commitments to purchase materials in connection with the Predecessor's growth projects as of December 31, 2013:

Year Ending December 31,	Operating Leases	Rights-of-Way	Purchase Commitments
		(in millions)	
2014	$ 7.4	$ 0.1	$ 3.9
2015	0.7	0.1	—
2016	—	0.1	—
2017	—	0.1	—
2018	—	0.1	—
Thereafter	—	0.5	—
Total	$ 8.1	$ 1.0	$ 3.9

Litigation Contingencies

The Predecessor is involved in various routine legal actions and proceedings arising in the normal course of its business. However, to the Predecessor's knowledge, there were no material pending legal proceedings to which the Predecessor is a party or to which any of its property is subject.

Environmental Contingencies

The operation of pipelines, plants and other facilities for gathering, processing or transmitting natural gas, NGLs and other products is subject to stringent and complex laws and regulations pertaining to health, safety and the environment. As an owner or operator of these facilities, the Predecessor must comply with United States laws and regulations at the federal, state and local levels that relate to air and water quality, hazardous and solid waste management and disposal, and other environmental matters. The cost of planning, designing, constructing and operating pipelines, plants, and other facilities must incorporate compliance with environmental laws and regulations and safety standards. Failure to comply with these laws and regulations may trigger a variety of administrative, civil and potentially criminal enforcement measures, including citizen suits, which can include the assessment of monetary penalties, the imposition of remedial requirements, and the issuance of injunctions or restrictions on operation. Management believes that, based on currently known information, compliance with these laws and regulations will not have a material adverse effect on the Predecessor's results of operations, financial condition or cash flows. At December 31, 2013, Predecessor had $0.3 million of liabilities recorded for environmental matters which are included in other long-term liabilities in the accompanying combined balance sheet.

ENLINK MIDSTREAM PARTNERS, LP

UNAUDITED PRO FORMA CONSOLIDATED FINANCIAL STATEMENTS AND NOTES

FOR THE YEAR ENDED DECEMBER 31, 2013

Introduction

Effective as of March 7, 2014, EnLink Midstream Partners, LP (formerly known as Crosstex Energy, L.P.) (the "Partnership") acquired, through one of its wholly owned subsidiaries, 50% of the outstanding equity interests in EnLink Midstream Holdings, LP (formerly known as Devon Midstream Holdings, L.P.), a wholly-owned subsidiary of Devon Energy Corporation ("Devon") referred to herein as "Midstream Holdings," and all of the outstanding equity interests in EnLink Midstream Holdings GP, LLC, the general partner of Midstream Holdings, in exchange for the issuance by the Partnership of 120,542,441 units representing a new class of limited partnership interests in the Partnership (collectively, the "business combination"). Midstream Holdings owns midstream assets in the Barnett Shale in North Texas and the Cana and Arkoma Woodford Shales in Oklahoma formerly owned by Devon, as well as the economic burdens and benefits of Devon's interest in Gulf Coast Fractionators in Mt. Belvieu, Texas.

Also effective as of March 7, 2014, Crosstex Energy, Inc. (to be renamed EnLink Midstream, Inc.) ("CEI"), became a wholly-owned subsidiary of EnLink Midstream, LLC (referred to as "ENLC"). Another wholly-owned subsidiary of ENLC owns the remaining 50% outstanding equity interests in Midstream Holdings. Devon owns the managing member of EnLink Midstream, and ENLC indirectly owns 100% of EnLink Midstream GP, LLC (formerly known as Crosstex Energy GP, LLC), the general partner of the Partnership (the "General Partner").

Unless the context requires otherwise, for purposes of this pro forma presentation, all references to "we," "our," or "us" refer to the Partnership and its directly owned and indirectly owned subsidiaries following the business combination, including the 50% limited partner interest in Midstream Holdings.

The unaudited pro forma financial statements of the Partnership are based on the historical audited financial statements of Midstream Holdings' Predecessor (the "Predecessor"), which comprises all of Devon's U.S. midstream assets and operations, including minor assets that were not included in the business combination. The 50% equity interest in Midstream Holdings owned by ENLC is reflected as a non-controlling interest in the unaudited pro forma financial statements. Under the acquisition method of accounting, Midstream Holdings is the acquirer in the transactions because its parent company, Devon, obtained control of the Partnership through the indirect control of the General Partner after the business combination. Consequently, Midstream Holdings' assets and liabilities will retain their carrying values. Additionally, the Partnership's assets acquired and liabilities assumed by Midstream Holdings as the Predecessor in the business combination will be recorded at their fair values measured as of the acquisition date. The excess of the purchase price over the estimated fair values of the Partnership's net assets acquired will be recorded as goodwill.

The unaudited pro forma consolidated balance sheet as of December 31, 2013 assumes the business combination and related transaction occurred on December 31, 2013. The unaudited pro forma consolidated statements of operations for the year ended December 31, 2013 assumes the business combination and related transactions occurred on January 1, 2013. The unaudited pro forma consolidated financial statements do not present the Partnership's actual results of operations had the business combination and related transactions been completed at the dates indicated. In addition, they do not project the Partnership's results of operations for any future period. The unaudited pro forma consolidated financial statements reflect the following significant assumptions and transactions:

- Devon's contribution of midstream assets located in the Barnett, Cana-Woodford and Arkoma-Woodford Shales, as well as a contractual right to the burdens and benefits associated with a 38.75% economic interest in Gulf Coast Fractionators, to Midstream Holdings;
- Devon's contribution of 50% of its limited partner interest in Midstream Holdings and all of its interest in the general partner of Midstream Holdings to a wholly-owned subsidiary of the Partnership in exchange for 120,542,441 Class B units in the Partnership, representing an approximate 52% limited partner interest in the Partnership;
- Midstream Holdings became a party to certain 10-year, fixed-fee gathering, processing and transportation agreements with Devon pursuant to which Devon will dedicate to Midstream Holdings specified natural gas production in the Barnett, Cana-Woodford and Arkoma-Woodford Shales; and
- the Partnership's assets acquired and liabilities assumed by Midstream Holdings as the Predecessor in the business combination have been recorded at their fair values with the excess purchase price over the estimated fair value of the Partnership's net assets acquired recorded as goodwill.

The unaudited pro forma consolidated financial statements and accompanying notes have been prepared in conformity with accounting principles generally accepted in the United States of America. These accounting principles are consistent with those used in, and should be read together with, the Predecessor's historical audited combined financial statements and related notes, which are included in Exhibit 99.4 to this Current Report on Form 8-K.

The adjustments reflected in the unaudited pro forma consolidated financial statements are based on currently available information and certain estimates and assumptions. Therefore, actual results may differ from the pro forma adjustments. However, management believes that the estimates and assumptions used herein provide a reasonable basis for presenting the significant effects of the business combination and the related transactions. Management also believes the pro forma adjustments give appropriate effect to the estimates and assumptions and are applied in conformity with accounting principles generally accepted in the United States of America.

ENLINK MIDSTREAM PARTNERS, LP

UNAUDITED PRO FORMA CONSOLIDATED BALANCE SHEET

	December 31, 2013					
	Predecessor Historical	Adjustments for Non-Contributed Assets(a)	Predecessor Historical, As Adjusted	Crosstex Energy, L.P. Historical	Pro Forma Adjustments (b)	Pro Forma, As Adjusted
	(in millions)					
Assets						
Current assets:						
Cash	$ —	$ —	$ —	$ 0.1	$ —	$ 0.1
Accounts receivable	0.4	—	0.4	295.0	—	295.4
Accounts receivable-affiliates	—	—	—	—	34.2(d)	34.2
Inventories, prepaid expenses and other	6.2	(0.4)	5.8	18.0	—	23.8

Total current assets	6.6	(0.4)	6.2	313.1	34.2	353.5
Property and equipment:						
Gross property and equipment	3,200.3	(262.4)	2,937.9	2,457.4	(375.7)	5,019.6
Accumulated depreciation	(1,359.9)	190.1	(1,169.8)	(603.1)	603.1	(1,169.8)
Total property and equipment, net	1,840.4	(72.3)	1,768.1	1,854.3	227.4(c)	3,849.8
Intangible assets:						
Gross intangible	—	—	—	539.9	(143.8)	396.1
Accumulated amortization	—	—	—	(227.9)	227.9	—
Total intangible assets, net	—	—	—	312.0	84.1(c)	396.1
Goodwill	401.7	—	401.7	153.8	1,936.5(e)	2,492.0
Equity investment	61.1	—	61.1	103.7	118.2(c)	283.0
Other long-term assets	—	—	—	22.4	(21.9) (c)	0.5
Total assets	$ 2,309.8	$ (72.7)	$ 2,237.1	$ 2,759.3	$ 2,378.5	$ 7,374.9
Liabilities and Partners' Equity						
Current liabilities:						
Accrued expenses and other	$ 44.7	$ (4.3)	$ 40.4	$ 329.9	$ 22.6(c)	$ 392.9
Total current liabilities	44.7	(4.3)	40.4	329.9	22.6	392.9
Long term debt		—	—	1,122.2	79.3(c)	1,201.5
Asset retirement obligations	14.9	(7.2)	7.7	—	—	7.7
Deferred income taxes	466.2	(25.3)	440.9	72.7	(432.7) (f)	80.9
Other	0.3	(0.3)	—	27.8	78.3(c)	106.1
Total liabilities	526.1	(37.1)	489.0	1,552.6	(252.5)	1,789.1
Partners' equity:						
EnLink Midstream Partners, LP equity	—	—	—	1,206.7	3,271.6(g)	4,478.3
Predecessor	1,783.7	(35.6)	1,748.1	—	(1,748.1) (g)	—
Total Partners' equity attributable to EnLink Midstream Partners, LP (228,497,409 common units issued and outstanding)	1,783.7	(35.6)	1,748.1	1,206.7	1,523.5	4,478.3
Non-controlling interests	—	—	—	—	1,107.5(g)	1,107.5
Total partners' equity	1,783.7	(35.6)	1,748.1	1,206.7	2,631.0	5,585.8
Total liabilities and partners' equity	$ 2,309.8	$ (72.7)	$ 2,237.1	$ 2,759.3	$ 2,378.5	$ 7,374.9

See accompanying notes to the pro forma consolidated financial statements.

ENLINK MIDSTREAM PARTNERS, LP

UNAUDITED PRO FORMA CONSOLIDATED STATEMENT OF OPERATIONS

	Year Ended December 31, 2013					
	Predecessor Historical	Adjustments for Non-Contributed Assets(a)	Predecessor Historical, As Adjusted	Crosstex Energy, L.P. Historical	Pro Forma Adjustments	Pro Forma, As Adjusted
	(in millions, except per unit data)					
Operating revenues:						
Operating revenues—affiliates	$ 2,180.9	$ (64.4)	$ 2,116.5	$ —	$ (1,482.0) (h)	$ 634.5
Operating revenues	209.8	(30.4)	179.4	1,943.2	(211.1) (h)	1,911.5
Total operating revenues	2,390.7	(94.8)	2,295.9	1,943.2	(1,693.1)	2,546.0
Operating expenses:						
Product purchases—affiliates	1,603.4	(15.2)	1,588.2	—	(1,588.2) (h)	—
Product purchases	170.3	(22.2)	148.1	1,547.0	(166.8) (h)(i)	1,528.3
Operations and maintenance	125.4	(21.9)	103.5	150.3	—	253.8
Operations and maintenance—affiliates	45.3	(9.1)	36.2	—	—	36.2
Depreciation and amortization	199.0	(12.0)	187.0	140.0	(26.2) (j)	300.8
General and administrative	47.0	(1.9)	45.1	68.1	—	113.2
Non-income taxes	18.0	(2.0)	16.0	—	—	16.0
Asset impairments	18.2	(18.2)	—	72.6	—	72.6
Other, net	0.5	—	0.5	(0.1)	—	0.4
Total operating expenses	2,227.1	(102.5)	2,124.6	1,977.9	(1,781.2)	2,321.3
Operating income	163.6	7.7	171.3	(34.7)	88.1	224.7
Interest expense	—	—	—	(76.2)	14.8(k)	(61.4)
Income from equity investment	14.8	—	14.8	—	—	14.8
Income before income taxes	178.4	7.7	186.1	(110.9)	102.9	178.1
Income tax expense (benefit)	64.2	2.8	67.0	2.3	(65.0) (l)	4.3
Net income (loss) from continuing operations	114.2	4.9	119.1	(113.2)	167.9	173.8
Non-controlling interests	—	—	—	—	113.7(m)	113.7
Net income (loss) attributable to EnLink Midstream Partners, LP	$ 114.2	$ 4.9	$ 119.1	$ (113.2)	$ 54.2	$ 60.1
Preferred interest in net income (loss) attributable to EnLink Midstream Partners, LP				$ 35.9	$ (35.9)	$ —
General partner interest in net income (loss)				$ (2.7)	$ 11.9(n)	$ 9.2
Limited partners' interest in net income (loss) attributable to EnLink Midstream Partners, LP				$ (146.4)	$ 197.3	$ 50.9

Net income (loss) attributable to EnLink Midstream Partners, LP per limited partners' unit:			
Basic and diluted per common unit			$ 0.23
Weighted average units outstanding:			
Basic and diluted common units			221.7(o)

See accompanying notes to the pro forma consolidated financial statements.

ENLINK MIDSTREAM PARTNERS, LP

NOTES TO UNAUDITED PRO FORMA CONSOLIDATED FINANCIAL STATEMENTS

1. Basis of Presentation

The unaudited pro forma consolidated financial statements give effect to the business combination and related transactions under the acquisition method of accounting. Under the acquisition method of accounting, Midstream Holdings will be the acquirer in the transactions because its parent company, Devon, will obtain control of the Partnership through the indirect control of the General Partner after the business combination. Consequently, Midstream Holdings' assets and liabilities will retain their carrying values. Additionally, the Partnership's assets acquired and liabilities assumed by Midstream Holdings as the Predecessor in the business combination will be recorded at their fair values measured as of the acquisition date. The excess of the purchase price over the estimated fair values of the Partnership's net assets acquired will be recorded as goodwill. The pro forma adjustments have been prepared as if the business combination and related transactions had taken place on December 31, 2013 in the case of the pro forma balance sheet and on January 1, 2013 in the case of the pro forma statements of operations. These adjustments and assumptions are described in Note 3 to these unaudited pro forma consolidated financial statements.

The unaudited pro forma consolidated financial statements should be read in conjunction with (i) the Predecessor's historical audited consolidated financial statements and related notes, as well as Management's Discussion and Analysis of Financial Condition and Results of Operations contained in Exhibit 99.3 and (ii) the Partnership's Annual Report on Form 10-K for the year ended December 31, 2013.

2. Summary of Significant Accounting Policies

The accounting policies used in preparing the unaudited pro forma consolidated financial statements are those used by the Predecessor as set forth in its audited historical combined financial statements contained in Exhibit 99.4 to this Current Report on Form 8-K.

3. Pro Forma Adjustments and Assumptions

The accompanying unaudited pro forma financial statements give pro forma effect to the following:

(a) The creation of Midstream Holdings and the removal of all amounts related to Devon's midstream assets that were not contributed to Midstream Holdings. In conjunction with the business combination, only the Predecessor's natural gas gathering and processing systems serving the Barnett, Cana-Woodford and Arkoma-Woodford Shales in Texas and Oklahoma and its 38.75% economic interest in Gulf Coast Fractionators were contributed to Midstream Holdings.

(b) Adjustments to reflect the business combination under the acquisition method of accounting. Under the acquisition method of accounting, tangible and identifiable intangible assets acquired, liabilities assumed and non-controlling interests are recorded at their estimated fair values. The excess of the purchase price over the preliminary estimated fair values of net assets acquired is recorded as goodwill. The estimated fair values and asset useful lives are based on preliminary estimates provided by third party valuation advisors and are subject to adjustment after the closing of the business combination based upon final analysis and review by our third party valuation advisors.

The following table summarizes the preliminary estimate of the purchase price and its allocation to the assets acquired and liabilities assumed (in millions, except unit price).

Midstream Holdings carryover basis:	
Total carryover basis	$ 1,748.1
Adjustment for change in Predecessor tax	432.7
Adjustment for working capital	34.2
Adjusted carryover basis	2,215.0
Less: Amount attributable to noncontrolling interests	(1,107.5)
Midstream Holdings consideration to controlling interests	1,107.5
Total consideration before noncontrolling interests	$ 2,215.0
EnLink Midstream Partners, LP outstanding units:	
Common units held by public unitholders	74.9
Common units held by Crosstex Energy, Inc.	18.0
Preferred units held by third party	16.6
Restricted units	1.2
Restricted units not subject to vesting	(0.4)
Total subject to exchange	110.3
EnLink Midstream Partners, LP common unit price(1)	$ 30.51
EnLink Midstream Partners, LP common units fair value	3,366.5
EnLink Midstream Partners, LP outstanding unit options value	4.3
EnLink Midstream Partners, LP consideration	$ 3,370.8
Total consideration and fair value of noncontrolling interests	$ 5,585.8

(1) The final purchase price is based on the fair value of the Partnership's common units as of the closing date, March 7, 2014.

The preliminary allocation of the purchase price is as follows (in millions).

Midstream Holdings carryover basis	$	2,215.0
EnLink Midstream Partners, LP fair values:		
Current assets		313.1
Property, plant and equipment, net		2,081.7
Intangible assets		396.1
Equity investment		221.9
Goodwill		2,090.3
Other long term assets		0.5
Other current liabilities		(352.5)
Long-term debt		(1,201.5)
Deferred income taxes		(72.7)
Other long-term liabilities		(106.1)
Total consideration and fair value of noncontrolling interests	$	5,585.8

The Partnership's fair values are based on preliminary management estimates. Management of the Partnership considered forecasted discounted future cash flows for the Partnership assets together with replacement costs to estimate the fair value of property, plant and equipment and the related customer relationship values included in intangible assets. The fair value of long-term debt was based on third-party market quotations for the Partnership's senior unsecured notes. The increase in accrued expenses and other long-term liabilities primarily relates to the recognition of a $100.9 million liability associated with an onerous performance obligation under a delivery contract. The Partnership has one gas delivery contract which requires it to

deliver a specified volume of gas each month at an index base price. The Partnership realizes a loss on the delivery of gas under this contract each month based on current prices. The fair value of this onerous performance obligation was based on forecasted discounted cash obligations in excess of market under this gas delivery contract.

(c) Adjustments necessary to reflect the Partnership's assets and liabilities at their estimated fair values.

(d) Adjustment to reflect obligation by Devon to the Partnership to eliminate the working capital deficit at consummation of the business combination.

(e) An adjustment to reverse the Partnership's $153.8 million of historical goodwill and an adjustment to reflect the $2,090.3 million of goodwill resulting from the business combination.

(f) The elimination of corporate federal deferred income tax liabilities of $432.7 million associated with the Predecessor. In conjunction with the business combination, Midstream Holdings created as a partnership, and its operating subsidiaries will be nontaxable entities, except for certain state taxes. Accordingly, the 50% interest in Midstream Holdings, including its subsidiaries, owned by the Partnership will not be subject to corporate federal income taxes.

(g) The elimination of the Partnership's historical equity balances and the recognition of the business combination consideration and the noncontrolling interests. Included below is a reconciliation between the historical and pro forma partners' equity (in millions).

	Predecessor, As Adjusted	EnLink Midstream Partners, LP	Non-controlling Interest	Total Partners' Equity
Historical Equity	$ 1,748.1	$ 1,206.7	$ —	$ 2,954.8
Pro forma adjustments:				—
Step-up of Partnership Units previously outstanding	—	2,159.8	—	2,159.8
Contribution of only 50% of Midstream Holdings	(874.1)	—	874.1	—
Change in tax status	216.4		216.3	432.7
Change for working capital	17.1	—	17.1	34.2
Partnership unit options	—	4.3	—	4.3
Reclass to EnLink Midstream Partners, LP equity	(1,107.5)	1,107.5	—	—
Total pro forma adjustments	(1,748.1)	3,271.6	1,107.5	2,631.0
Pro forma partner's equity	$ —	$ 4,478.3	$ 1,107.5	$ 5,585.8

(h) Two duly authorized contract changes that pertain to the assets owned by Midstream Holdings take effect upon completion of the business combination. The first contract change converts the natural gas processing percent-of-proceeds contracts to fixed-fee contracts. This contract change increases operating revenues as presented in the table below. The second contract change results in ceasing to take title to the natural gas gathered and processed and the NGLs fractionated. This contract change decreases both operating revenues and product purchases as presented in the following table. The entry into commercial agreements reflecting these changes is a condition to the Partnership's obligation to consummate the contribution transactions, which must be completed substantially concurrently with the Mergers. Please see "Exhibit 99.3—Management's Discussion and Analysis of Financial Condition and Results of Operations of EnLink Midstream Holdings, LP Predecessor—Certain Relationships and Related Party Transactions—Commercial Arrangements—Gathering and Processing Agreements."

Additionally, Crosstex received revenues from Midstream Holdings as a customer during the periods presented. These revenues are reclassified from operating revenues to operating revenues—affiliates as presented in the following table.

	Year Ended December 31, 2013 (in millions)
Operating revenues—affiliates:	
Conversion to fixed-fee contracts	$ 34.0
Cease taking title to products	(1,588.2)
Reclassification of affiliate revenues	72.2
Operating revenues—affiliates pro forma adjustments	(1,482.0)
Operating revenues:	
Conversion to fixed-fee contracts	9.2
Cease taking title to products	(148.1)
Reclassification of affiliate revenues	(72.2)

Operating revenues total pro forma adjustments	(211.1)
Total operating revenues total pro forma adjustments	$ (1,693.1)
Cease taking title to products:	
Product purchases—affiliates	$ (1,588.2)
Product purchases	$ (148.1)

(i) The adjustment to product purchases attributable to the contract changes per adjustment (h) above and the reduction of the Partnership's monthly product purchase costs in excess of market associated with an onerous performance obligation under a gas delivery contract. Included in the fair value adjustment (c) above for other current and long-term liabilities are amounts to recognize a $100.9 million total liability for this onerous performance obligation. The Partnership has one delivery contract which requires it to deliver a specified volume of gas each month at an indexed base price. The Partnership realizes a loss on the delivery of gas under this contract each month based on current prices. The fair value of this onerous performance obligation was based on forecasted discounted cash obligations in excess of market under this gas delivery contract. For pro forma purposes, the portion of the monthly product purchase costs in excess of market associated with this onerous performance obligation are now assumed to reduce the liability rather than be recognized as expense. The following summarizes the pro forma adjustments to product purchases.

	Year Ended December 31, 2013 (in millions)
Contract changes in adjustment (h) above	$ (148.1)
Performance obligation in adjustment (i)	(18.7)
Product purchases total pro forma adjustment	$ (166.8)

(j) Adjustments to depreciation and amortization resulting from the effects of the purchase accounting adjustments in (c) above and the effects of increasing the estimated useful lives used to calculate depreciation and amortization. The longer estimated useful lives correspond to the expected lives used to determine the fair values of property, plant and equipment and related identifiable intangible assets. The depreciable lives used for pro forma purposes are based on a preliminary third party valuation. Expected useful lives and amortization periods related to depreciation and amortization pro forma adjustments are as follows:

	Useful Lives
Tangible Assets:	
Transmission Assets	20 - 25 years
Gathering Systems	20 - 25 years
Gas Processing Plants	20 - 25 years
Other property and equipment	3 - 15 years
Intangible Assets:	
Customer Relationships	10 - 20 years

The pro forma adjustments decreased historical depreciation and amortization expense by $26.2 million for the year ended December 31, 2013, primarily due to the $143.8 million decrease in gross intangible assets subject to amortization and the $375.7 million decrease in gross property costs subject to depreciation without a corresponding decrease in the estimated useful lives of the overall assets as a result of the purchase accounting adjustments per (c) above. Although the net impact of the purchase accounting adjustments was an increase of $84.1 million in net intangible assets and an increase of $227.4 million in net property, plant and equipment, depreciation and amortization expense for the pro forma period did not increase because the purchase accounting adjustments allocated a significant portion of the fair value to assets acquired and/or developed during the past two years which have a longer economic life than the historical assets purchased prior to 2007.

(k) Adjustments to historical interest expense were made to reduce pro forma interest expense, using the effective interest rate method, to correspond with the $79.3 million increase in long-term debt due to the fair value adjustment, which is based on third-party market quotations for the Partnership's 8.875% senior unsecured notes (the "2018 Notes") and its 7.125% senior unsecured notes (the "2022 Notes") as of December 31, 2013, per (c) above. The effective pro forma interest rates for the Partnership's 2018 Notes and 2022 Notes are 7.66% and 5.49%, respectively. An increase or decrease of 1/8 of 1% in pro forma interest rates would result in a corresponding increase or decrease to pro forma interest expense of approximately $1.4 million for the year ended December 31, 2013. For pro forma purposes, the interest costs in excess of the fair value of the long-term debt as of December 31, 2013 are assumed to reduce the long-term debt rather than be recognized as interest expense.

(l) Reflects the elimination of corporate federal income tax expense attributable to the 50% interest in Midstream Holdings that will be owned directly by the Partnership. In conjunction with the business combination, Midstream Holdings was created as a partnership, and its operating subsidiaries are nontaxable entities, except for certain state taxes. Accordingly, the 50% interest in Midstream Holdings, including its subsidiaries, owned by the Partnership will not be subject to corporate federal income taxes.

(m) Income attributable to non-controlling interests represents the 50% interest in Midstream Holdings, including its subsidiaries.

(n) Reflects the increase in the net income allocation to the General Partner due to the increase in its proportionate interest share of pro forma net income relative to the acquisition adjustments and pro forma adjustments and the increase in General Partner's incentive distribution rights resulting from the increased aggregate pro forma distributions related to the issuance of 120,542,441 new Class B common units assuming the historical per unit distributions for the applicable periods.

	Year Ended December 31, 2013 (in millions)
General Partner share of income (loss)	$ 2.7
Increase in incentive distribution rights	9.2
Net General Partner Adjustment	$ 11.9

(o) Basic earnings per unit was computed by dividing net income by the weighted average number of pro forma units outstanding. Adjustments to reflect basic and diluted weighted average units outstanding.

	Year Ended December 31, 2013 (in millions)
Partnership historical weighted average common units	84.6
Total Partnership Units	84.6
Pro Forma Adjustments:	
Assumed 100% conversion of Enlink Midstream Partners, LP preferred units	16.6
Issuance of EnLink Midstream, LP Class B Units	120.5
Total pro forma weighted average units outstanding	221.7